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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates

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Preface

This report, *Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates*, is the second in a series mandated by Title XIII, Section 1340, "Establishment of Data Base and Study of Transportation Rates," of the Energy Policy Act of 1992 (P.L. 102-486). The first report *Energy Policy Act Transportation Study: Availability of Data and Studies*, was submitted to Congress in October 1993; it summarized data and studies that could be used to address the impact of legislative and regulatory actions on natural gas transportation rates and flow patterns. The current report presents an interim analysis of natural gas transportation rates and distribution patterns for the period from 1988 through 1994. A third and final report addressing the transportation rates and flows through 1997 is due to Congress in October 2000.

This analysis relies on currently available data; no new data collection effort was undertaken. The need for the collection of additional data on transportation rates will be further addressed after this report, in consultation with the Congress, industry representatives, and in other public forums.

This report has been prepared by the Energy Information Administration (EIA), 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 (202/586-6090), Director of the Reserves and Natural Gas Division. Detailed questions on specific sections of the publication may be addressed to the following analysts:

- Chapter 1. "Introduction," Barbara Mariner-Volpe (202/586-5878).
- Chapter 2. "Federal Regulations, Policies, and Directives," Barbara Mariner-Volpe (202/586-5878).
- Chapter 3. "Transportation Flow Patterns," James Tobin (202/586-4835).
- Chapter 4. "Trends in Natural Gas Transportation Rates," Barbara Mariner-Volpe (202/586-5878).
- Chapter 5. "Data Sources," Margaret J. Jess (202/586-7499).
- Appendix A. "Overview of Pipeline Design and Operational Factors," James Tobin (202/586-4835).
- Appendix B. "Regional Profiles: Pipeline Capacity and Service," James Tobin (202/586-4835).
- Appendix C. "Data Sources," James Tobin (202/586-4835).
- Appendix D. "FERC Ratemaking Process," Barbara Mariner-Volpe (202/586-5878).
- Appendix E. "Corridor Rate Analysis Results," Barbara Mariner-Volpe (202/586-5878).
- Appendix F. "Companies with Electronic Tariffs on File at FERC," James M. Thompson (202/586-6201).

The overall scope and content of the report was supervised by Barbara Mariner-Volpe. Significant analytical contributions were made by: Mary Lashley Barcella—Chapter 4, Christopher L. Ellsworth—Chapters 2 and 4, Jason Feld—Chapters 3 and 4, Kevin F. Forbes—Chapter 4, Marie-Beth Hall—Chapters 2 and 5, John H. Herbert—Chapters 3 and 4, James O'Sullivan—Chapter 4, Phil Shambaugh—Chapter 3, Michael J. Tita—Chapter 4, William Trapmann—Chapter 3, and Lillian (Willie) Young—Chapter 3.

Editorial support was provided by Marie-Beth Hall, Doris Wells, Ann Whitfield, and Lillian Young. Desktop publishing support was provided by Margareta Bennett.

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Executive Summary

Legislative initiatives, regulatory changes, and market forces have reshaped the natural gas industry during the past decade. While legislation and policy initiatives have created the conditions necessary for markets to expand, regulatory reform has focused on creating a more efficient and competitive market. This market reform has centered on the restructuring of interstate pipeline companies and their relationships with producers, local distribution companies (LDC's), and end users.

Regulatory reform has shifted the responsibility for gas purchasing from the pipeline companies to some end users and to the LDC's. These purchasers now can negotiate with many different suppliers, contract with pipeline companies for transportation service, and select and combine an assortment of other services to satisfy their needs. Accordingly, transportation patterns have been affected because customers make their own arrangements for service. Now that gas is no longer bought from interstate pipeline companies as part of a bundled service, the rate structure for transportation and other services provided by pipeline companies has also changed significantly.

Transportation tariffs for interstate pipeline companies are determined in Federal Energy Regulatory Commission (FERC) proceedings and are based on the total cost of providing pipeline service. Many factors influence total costs, and therefore final tariff rates, including up-front capital costs, capital depreciation, the allowed rate of return, operation and maintenance costs, gas throughput, and service quality. Also, rate design and the allocation of a pipeline company's fixed and variable costs can have an enormous impact on rates for different types of customers. For example, in 1992 FERC adopted the straight fixed-variable (SFV) rate design, allocating all fixed costs to a pipeline capacity reservation fee and all variable costs to a commodity or usage fee. This change moved approximately $1.7 billion from the usage to the reservation fee, putting downward pressure on rates to consumers with relatively constant consumption patterns and upward pressure on rates to seasonal consumers.

This report is the second in a series of three reports requested by the U.S. Congress under Section 1340 of the Energy Policy Act of 1992. It examines how the Clean Air Act Amendments (CAAA) and other Federal actions have affected transportation patterns and rates for natural gas from 1988 through 1994. The legislative, regulatory, and market developments during this period have been so extensive that it is difficult to evaluate separately the effects of any one event such as the CAAA. However, to the extent that these developments alter natural gas consumption and production or allow more flexibility in rates and services, natural gas flows and rates are affected. Chapter 1 briefly highlights the extensive changes in natural gas policy and markets during the past decade, while Chapter 2 summarizes the Federal laws and policies that have affected interstate transportation rates and flows. Subsequent chapters:

- Address the changing patterns of interstate gas flows, shifts in consumption and production, and the increased importance of imported gas from Canada (Chapter 3).

- Analyze the changes in maximum rates for transportation services in selected market areas, the effect of capacity release trading on interstate pipeline company rates, and trends in consumer transmission and distribution prices (Chapter 4).

- Present an update of information sources and data collection that could be used to assess the impacts of legislative and regulatory actions on transportation flows and rates (Chapter 5).

Improvements in electronic information systems during the past few years have increased the availability of some natural gas data. Despite these advances, many questions relating to pipeline rates cannot be addressed. For example, substantial information is available regarding capacity release transactions posted on the electronic bulletin boards, including the actual rates paid. However, these transactions represent only 13 percent of total deliveries. Thus, coverage of a significant part of the transportation market is not publicly available. The Energy Information Administration (EIA) continues to evaluate and monitor the need for future data collection in this and other areas.

Recent Regulatory and Legislative Actions Have Altered Natural Gas Markets

Arguably, the most significant regulatory actions that affected interstate transportation rates between 1988 and 1994 were FERC Orders 436 and 636 that restructured the natural gas industry. Order 436 encouraged, and Order 636 required, pipeline companies to provide customers equal access to unbundled pipeline services. Order 636, issued April 8, 1992, required interstate pipeline companies to unbundle, that is separate, their sales and transportation services by the beginning of the 1993-94 heating season (November 1, 1993). The net result was to provide other parties with access to capacity on interstate pipelines, leading to increased competition among gas sellers and buyers, diminished market power for pipeline companies, higher throughput, and lower transmission markups

(Figure ES1). There are two key provisions of Order 636 that have an impact on rates: (1) the change in rate design; and (2) the capacity release program.

During the period of this study, 1988 through 1994, some other major legislative and policy initiatives contributed to increased natural gas use in the U.S. economy. A major objective of policy makers during this period was to provide the regulatory and legislative framework that would ensure adequate energy supplies and also protect environmental quality. The Clean Air Act Amendments of 1990 (CAAA) provided opportunities for the expansion of the natural gas market. Other legislation and policy directives, including the U.S./Canadian Free Trade Agreement, the Natural Gas Wellhead Decontrol Act, and the amendment of the Power Plant and Industrial Fuel Use Act, also have had far-reaching implications for the industry. In general, legislation has increased market competition and encouraged the production and use of natural gas. (The initiatives have also affected transportation and distribution patterns.)

While CAAA Effects Are Limited to Date, Future Requirements Are Likely to Have a Greater Market Impact

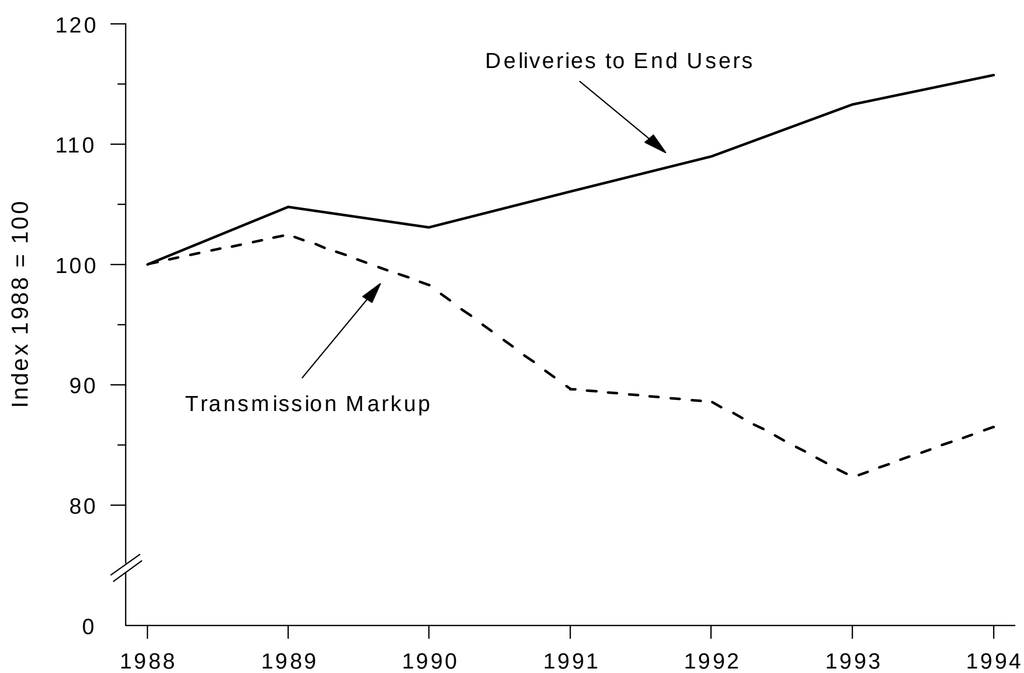
The CAAA created new air quality standards that require companies to install more advanced pollution control equipment and to make other changes in industrial operations that will lead to reductions in emissions of air pollutants. The amendments are expected to increase the use of natural gas by electric utilities and to expand its commercial use in vehicles.

The upper Midwest and the New England areas are expected to use more gas-fired generators to produce electricity, while California is expected to continue leading the Nation in the use of natural gas-fueled vehicles. Subsequent phases of the Clean Air Act cover the period beginning in 2000, and require lower future emission levels. Natural gas use should rise as generators increase operations of existing gas-fired plants and retrofit other facilities for gas use. In addition, some new capacity fueled by natural gas is expected to be built in the future. The CAAA could have significant effects on future U.S. demand and supply levels and influence regional flow patterns, although the impacts are limited at present.

Regulatory Policies and Market Changes Have Contributed to Almost $6.5 Billion in Annual Savings to Gas Consumers

In total, EIA estimates that consumers paid almost $6.5 billion (9 percent) less, in real terms, for natural gas service (including wellhead purchases combined with transmission and distribution charges) in 1994 than they would have in 1988. This estimate includes $2.5 billion in reduced transmission and distribution charges and $4 billion of savings resulting from the 11-percent reduction in wellhead prices since 1988. The bulk of the $2.5 billion represents the reduction in the fixed costs of transmission

Figure ES1. Indices of Natural Gas Transmission Markups and Deliveries to End Users, 1988-1994



Sources: Energy Information Administration, Office of Oil and Gas, derived from: **1988:** *Historical Monthly Energy Review 1973-1992* (August 1994). **1989-1994:** *Natural Gas Monthly* (August 1995).

and distribution that do not vary with the volumes delivered. Because of data limitations, the estimate of total savings may be low because for offsystem industrial customers only the savings in wellhead prices are included. However, of the $6.5 billion savings, industrial customers were the main beneficiaries, receiving over half of the savings ($3.8 billion), while electric utilities and commercial customers each saw savings of $1.4 billion.

Another way to estimate savings is to compare the average price per thousand cubic feet to each end-use sector in 1994 and 1988. This method assumes that transmission and distribution costs would vary with the volumes delivered. In 1994, the price of 1 thousand cubic feet of gas (wellhead price plus delivery charges) to the various end-use sectors had decreased between 3 and 19 percent from 1988 levels (Table ES1).

Between 1988 and 1994, total transmission and distribution markups (the average unit cost of combined transportation and distribution services) to the residential and commercial sectors remained fairly constant in real terms, while comparable prices to the industrial and electric utility sectors declined by 20 and 42 percent, respectively (Figure ES2). Although total markups to captive residential and commercial consumers have remained unchanged, these customers appear to have benefited from the increased competition in natural gas markets brought about by changes in Federal policies. From 1988 through 1994, the average cost of transmission service from the wellhead to the local distributor decreased 16 percent, but this decrease was almost completely offset by 7 and 13 percent increases in the cost of distribution from the citygate to the residential and commercial end users, respectively.

Federal Policies Also Affect Transportation Rates: Impact Varies by Customer Class

Based on an examination of selected transportation markets, customers with relatively constant rates of gas consumption generally benefited more than customers with variable patterns of consumption from the change to straight fixed-variable (SFV) rates mandated by FERC Order 636. The results are based on a comparison of maximum tariff rates (maximum regulated rates), including transition costs, for firm transportation service during 1991 (pre-Order 636) and 1994 (post-Order 636) along 21 routes from supply to market areas.

The pattern of gas consumption during the year varies by customer. Some customers, such as large industrial plants, consume gas at a fairly constant level throughout the year (high-load-factor customers), while others, such as residential consumers, alter their consumption with the seasons (low-load-factor customers). Although other influences may have mitigated SFV's downward pressure on high-load-factor rates and upward pressure on low-load-factor rates, the change in rate design was the dominant influence in widening the gap between the rates paid by the two groups. Except for the change in rate design, other key determinants of firm rates would tend to have the same general impact on customers regardless of their load factors.

The analysis of maximum allowable rates suggests that low-load-factor customers have benefited less than high-load-factor customers from the recent regulatory changes. Although both categories of customers had increases and decreases in tariffs, the change was more advantageous to the high-load-factor customers. In those cases where rates to high-load-factor customers increased, rates to low-load-factor customers increased even more in both absolute and percentage terms. Also, if both categories of customer experienced a decrease in rates, the decrease was always larger for the high-load-factor customer. In about half the cases considered, rates to the high-load-factor customers declined, while rates to the low-load-factor customers either decreased by a smaller amount or actually increased. For example, on the Gulf Coast to Louisville route, the high-load-factor rate declined by 18 percent while the low-load-factor rate increased by 9 percent.

Comparing pre- and post-Order 636 rates in the corridors served by multiple pipelines suggests that transportation services offered by different pipeline companies may have become more similar. The rate variation among pipeline companies in a corridor has decreased, particularly for low-load-factor customers. However, the convergence in rates for high-load-factor customers results from a decline in the high-end rates combined with an increase in the low-end rates, while the convergence in rates for low-load-factor customers results from low-end rates moving up to the level of high-end rates. Order 636's directive to use a common rate design method for all pipeline companies may have led to more similarity in the rates offered by pipeline companies serving the same corridor.

New Capacity Trading Mechanism Lowers the Cost of Gas Transmission

Another major development in the restructured transportation market was the establishment of a secondary market in pipeline capacity. Prior to Order 636, capacity rights on a pipeline were

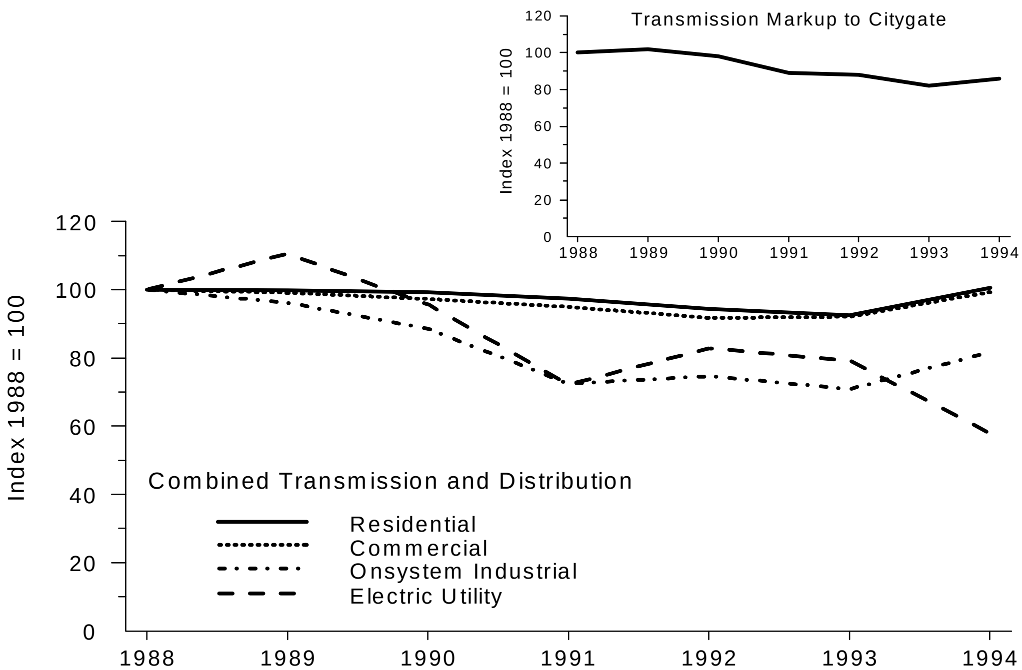
Table ES1. Average Natural Gas Prices and Price Changes, 1988 and 1994
(1994 Dollars per Thousand Cubic Feet)

Price	1988	1994	Price Change	Percent Change
Wellhead	2.05	1.83	-0.22	-11
Citygate	3.54	3.08	-0.46	-13
End Use				
Residential	6.64	6.41	-0.23	-3
Commercial	5.62	5.43	-0.19	-3
Onsystem Industrial	3.58	3.05	-0.53	-15
Electric Utility	2.83	2.28	-0.55	-19

Note: Industrial end-use price data represent onsystem sales only. The onsystem share of total sales to industrial consumers declined from 43 percent in 1988 to 22 percent in 1994.

Sources: Energy Information Administration. **1988**: *Natural Gas Annual 1992*, Vol. 2 (November 1993). **1994**: *Natural Gas Monthly* (August 1995).

Figure ES2. Indices of Transmission/Distribution Markups by Sector, 1988-1994



Notes: Industrial markups reflect end-use prices for onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

Source: Energy Information Administration, Office of Oil and Gas, derived from: **1988:** *Natural Gas Annual, Vol. 2* (November 1993); **1989-1994:** *Natural Gas Monthly* (August 1995).

nontransferable. A customer could either use the capacity itself or it would be available to the pipeline company with no compensation to the customer. Under Order 636, a shipper with excess reserved capacity can release it in return for a credit on its reservation charge. Total credits during the period November 1993 through March 1995 were approximately $568 million, of which $528 million was generated from pipeline capacity releases and $40 million from storage capacity releases.

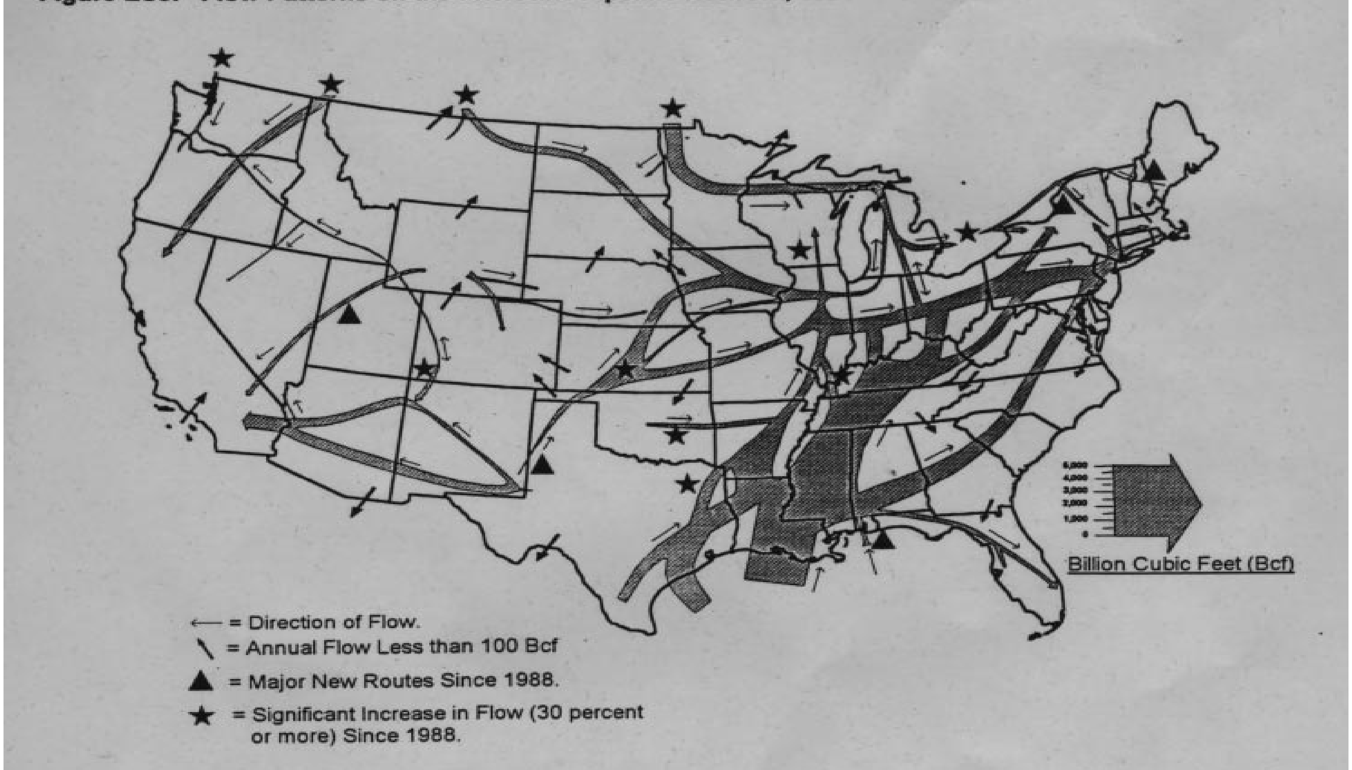
While less than 2 years old, the capacity release market currently represents 13 percent of the overall volume of gas moved to market in 1994. Rates for capacity release transportation represent an average 64 percent discount from the maximum firm transportation rate. Rates for released capacity vary from region to region. The Southeast Region, with its expanding gas market and limited capacity available for release, has the highest rate for released capacity—more than three times the national average price. The average U.S. price for released pipeline capacity has been fairly stable with only modest seasonal fluctuations during the winter months.

The capacity release market not only reduces the cost of reserving capacity on the system. It also provides replacement shippers with a generally lower cost alternative to capacity obtained directly from the pipeline company. Before this market emerged, competition along a corridor was limited. As a result of the emergence of the secondary market, the number of potential suppliers of firm capacity has increased significantly because each holder of firm capacity may release that capacity. This translates into a substantial increase in the degree of effective competition in the market for pipeline capacity. It preserves the economies of scale inherent in transmission while effectively providing for a competitive and thus more efficient market in pipeline capacity.

Major Shifts in Supply and Demand Have Altered Natural Gas Flows

The principal flow patterns of natural gas from supply areas to markets in the lower 48 States have not changed significantly since 1988. However, several new routes and major increases on several existing routes have developed (Figure ES3). The major change has been the rapid growth in imports of natural gas from Canada, principally to serve markets in California, the Midwest, and Northeast. In 1994, imports of Canadian natural gas were 2.6 trillion cubic feet, double the level in 1988. Currently, Canadian gas accounts for approximately 13 percent of U.S. gas consumption, up from 7 percent in 1988. Another major shift has been the development of pipeline capacity extending from the Central to the Western Region as well as within the Central Region itself. Most of this development has been to move new supplies from the Rocky Mountain area of Colorado and Wyoming and the coalbed methane fields of southern Colorado and northern New Mexico.

Figure ES3. Flow Patterns on the Interstate Pipeline Network, 1994



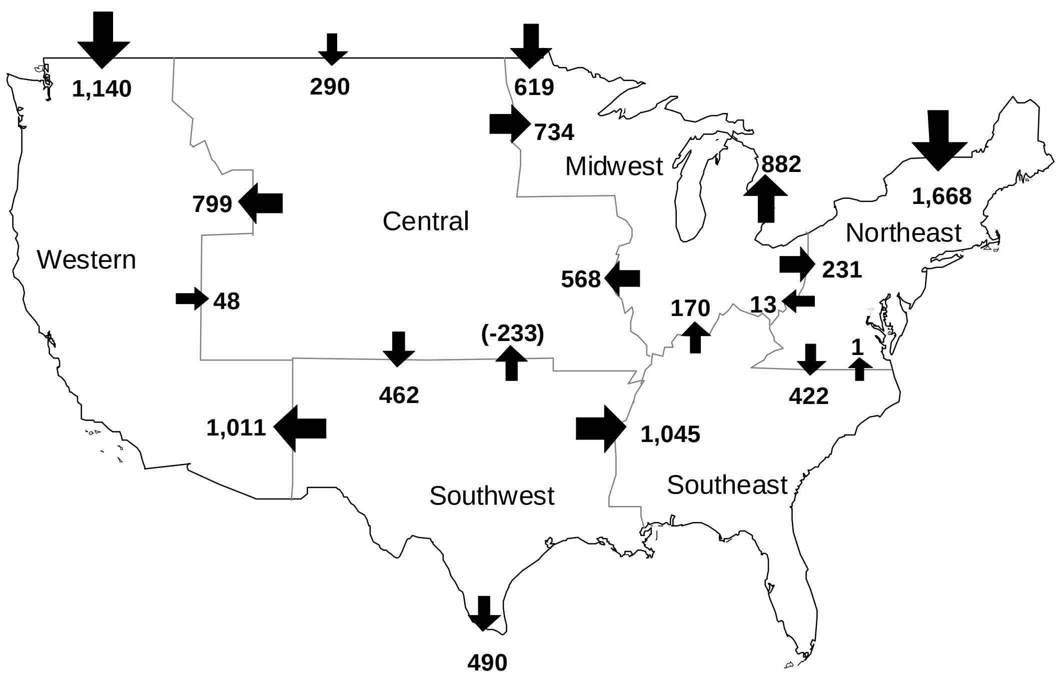
Source: Energy Information Administration, Office of Oil and Gas.

These shifts in gas flows can be attributed to many elements. Changes in flow patterns are driven by changes in demand and supply patterns, which vary considerably by region and sector because of differences in regional gas production and delivery costs, climate conditions, population density, and gas penetration rates. Legislative and regulatory policies vary in their impact on the trends and patterns in flows between the regions because of these differences.

Natural gas consumption has increased by 15 percent since 1988 with most of the growth occurring in the industrial sector, which includes nonutility generation of electricity. This increased consumption has been supported by an increase in U.S. production of 1.8 trillion cubic feet (10 percent) as well as by the increased imports from Canada. The increased gas flows have also been supported by significant expansion of the physical network of pipelines and storage facilities, and by the increased flexibility and accessibility of the system that resulted from regulatory changes. Interregional pipeline capacity has increased by more than 10 billion cubic feet per day since 1990, from 75.5 to 85.9 billion cubic feet per day (Figure ES4).

A more general change to flow patterns has been brought on by the fundamental shift in the role of pipeline companies from sellers to transporters of gas for others. Although mandated by FERC Order 636, market forces had already been moving the industry in this direction. In 1994, approximately 96 percent of all natural gas transported on the interstate system represented transportation of gas for others, compared with 56 percent in 1986 and only 21 percent in 1981 when pipeline companies were primarily sellers of gas. The requirement under FERC Order 636 that all shippers have open access to transportation and storage services has also led to development of many market or supply hubs with numerous pipeline interconnections and services and access to storage facilities.

Figure ES4. Interregional Additions to Capacity on the Interstate Pipeline Network, 1991 Through 1994
(Volumes in Million Cubic Feet per Day)



Note: This figure has been revised and corrected since its original publication.
Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, August 1995.

1. Introduction

This is the second in a series of three reports requested by the U.S. Congress (under Section 1340 of the Energy Policy Act of 1992) to assess the impact of the Clean Air Act Amendments of 1990 and other Federal policies on natural gas transportation patterns and rates. This report is an interim analysis addressing the impacts of Federal policies on transportation rates and flow patterns from 1988 through 1994. The third report requested under Section 1340 will update the analysis through the year 1997. That report is to be completed by October 2000.

In the first report, *Energy Policy Act Transportation Rate Study, Availability of Data and Studies,* submitted to Congress in October 1993, the Energy Information Administration (EIA) examined the availability of data and other studies that could be used to evaluate the effects of Federal policies. The report found that sufficient information was available to address transportation patterns as EIA collects annual data on State-to-State flows of natural gas. However, this was not the case with transportation rates, and EIA determined that no comprehensive data sources or studies were in place or under development. EIA recommended in the initial report that a data collection effort be undertaken to obtain information on transportation rates. Further action on this effort has been postponed, however, and this analysis was undertaken using currently available information. The decision to defer action on a data collection effort was based on the following. First, transportation rates and arrangements have been changing rapidly during the past 2 years. Second, it was thought that further standardization and easier access to electronic bulletin boards may provide better information than was initially available at the time of the October 1993 assessment. EIA concluded that it would be useful to allow these areas to develop more fully before initiating additional data collection.

EIA is continuing to evaluate and monitor the need for future data collection on the transportation market. The need for additional information will be addressed as part of the triennial review and reclearance of EIA forms used to collect natural gas data. The forms are scheduled to be recleared by December 1996. There will be an extensive public comment period during which the need for this type of information will be discussed with both users of the data and the potential respondents.

Changes in Federal Policy

For the natural gas industry, the past decade has been marked by some of the most significant changes in Federal policy since the Supreme Court Phillips decision in 1954 resulted in the imposition of wellhead price regulation on interstate sales of natural gas. These changes include legislative initiatives as well as regulatory adjustment to changing market conditions. For example:

- The repeal of the Power Plant and Industrial Fuel Use Act in 1987 removed restrictions on the use of natural gas by large industrial consumers and electric utilities. This provided the natural gas industry the opportunity to compete for the expansion of these markets. It also illustrated the developing confidence in the availability of domestic supplies to support expanded use of natural gas.

- More than 30 years after the Phillips decision, the Natural Gas Wellhead Decontrol Act of 1989 removed all price controls on the wellhead sales of natural gas as of January 1, 1993, allowing the price of natural gas to be freely set in the marketplace.

- In 1985, the Federal Energy Regulatory Commission (FERC) began the first of a series of regulatory actions designed to improve the competitiveness of the market. A more competitive market would give customers of the interstate pipeline companies more service options and allow the ultimate consumers to benefit from the deregulation of wellhead prices. By 1993, the operational structure of the interstate transmission industry had been transformed. Prior to these rulings, interstate pipeline companies often acted as both transporters and merchants of natural gas, bundling the sales and transmission of gas into one service. The Restructuring Rule (Order 636 issued in 1992) required that these services be separated and pipeline customers be given the opportunity to contract for onlythe specific services they needed from the pipeline companies. As part of the regulatory restructuring, interstate transportation rates were adjusted as well to allow for more efficient allocation of capacity.

- Environmental and national security concerns have prompted legislation that encourages increased use of natural gas because of its relatively clean-burning characteristics in comparison with other fossil fuels. The Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992 provide opportunities for increased natural gas use in transportation and in the generation of electricity.

Market Response

From 1988 through 1994, the market changed dramatically, both as a result of economic pressures and as a result of the Federal initiatives. Between 1988 and 1994:

- Gas production increased by 10 percent, whereas real wellhead prices and proved reserves declined by 11 and 2 percent, respectively. This demonstrated ability to produce more gas from fewer reserves despite lower real prices provides evidence that improved efficiency and technology have fundamentally altered the gas supply process.

- Gas delivered to consumers increased by 16 percent to reach the highest level since 1974. Much of the increase is related to the increased use of natural gas for electricity generation by nonutility generators.

- Prices to consumers dropped significantly, as customers benefited from declining wellhead prices and lower transmission costs.

Analytical Approach

The report addresses the changes in the industry from the period from 1988 through 1994. The extensive market and complex institutional changes that have taken place interact to such an extent that it is difficult, costly, and perhaps counterproductive to attempt to separate these effects or draw conclusions of the impact of a particular regulatory or legislative change. However, the effects of regulatory restructuring on the market have been pervasive, affecting both transportation rates and flow patterns, throughout this period. The effects of the Clean Air Act Amendments are much less certain. It is likely that the most significant impacts on the market from the amendments will be seen in the future, particularly as the Phase II emission standards become effective.

To capture the interaction among these institutional changes, the report provides a broad discussion of the major influences on transportation flows and rates, discusses in qualitative terms how specific changes, such as the Clean Air Act Amendments of 1990, affect the market and provides some quantification of the overall changes in transportation flows and rates. However, there is no comprehensive source of information on actual transportation rates, and this places limitations on the analysis. Specifically:

- The analysis of rates was based on maximum tariff rates. These rates may not represent the actual rates paid because of discounting which is taking place.

- The restructuring of services under Order 636 has affected the way these services are accounted for in the data. For example, firm transportation service may have included storage services prior to Order 636, but now storage services are priced separately. Thus, only aggregate costs of transmission and distribution services are examined.

The analysis presented in this report draws on a number of public and private information sources. The examination of transportation patterns and aggregate measures of transportation margins relies on data collected by EIA. The interstate pipeline capacity information is drawn from FERC source material. The more detailed examination of transportation rates is based on information collected by FERC as well as private data sources for capacity release information and pipeline rates along selected corridors. All of these data sources are discussed in Chapter 5 of the report.

This chapter has highlighted the extensive changes in the natural gas industry and market at a national level. Much more of the story is at the regional level, as changing market and supply conditions have driven substantial changes in the interstate system. The following chapters present analysis at the regional level as well as more detailed analysis of the changes at the national level. Chapter 2 provides a summary of the Federal laws and policies that have affected rates and interstate transportation flows. The legislative and regulatory changes are discussed in chronological order, beginning with the issuance of Order 436 in 1985. While this Order is outside the time period analyzed in the report, it was the basis for many other regulatory changes that influenced transportation patterns and rates from 1988 through 1994. Chapter 3 addresses the changing patterns of interstate natural gas flows. It includes an analysis of the underlying changes in regional supply availability and demand requirements that are driving the changes in flow patterns. The analysis of the effects of Federal policy on transportation rates is given in Chapter 4. Finally, Chapter 5 presents an update of data collections and other studies that may be applicable to the EPACT requirements.

2. Federal Regulations, Policies, and Directives

The natural gas market has been radically transformed during the past 7 years. Regulatory reform instituted by the Federal Energy Regulatory Commission (FERC) has created a more competitive market by changing the operating procedures for interstate pipeline companies. Prior to this reform, interstate pipeline systems bought natural gas from producers, transported it along their pipelines, and then resold it to local distribution companies (LDC's). A series of FERC orders, starting with Order 436 and culminating in Order 636, effectively unbundled these services so that interstate pipeline companies no longer own the gas transported on their pipeline systems, but transport it for third parties. Purchasers of natural gas now can negotiate price provisions and contract terms with many different suppliers, while contracting separately with pipeline companies for transportation, storage, and various other services, selected and combined, to satisfy their needs. To facilitate this, a new type of industry player has emerged—the independent gas marketer, who in addition to marketing gas supply can serve as the purchaser's agent in making all the arrangements necessary to get the gas delivered; providing, in essence, a "package" of sales and transportation services. Deregulation and market restructuring have directly contributed to growth in gas storage for managing seasonal inventories, the development of a secondary transportation market, and better information about commodity and transportation prices via commodity markets and electronic bulletin boards. Price signals for natural gas are quickly transmitted between the consumer and the producer, and regional markets are more integrated.

The Clean Air Act Amendments of 1990 provided opportunities for the expansion of the natural gas market. Other legislation and policy directives, including the U.S.-Canadian Free Trade Agreement, the Natural Gas Wellhead Decontrol Act, and the repeal of the Power Plant and Industrial Fuel Use Act, also have had far-reaching implications for the natural gas industry. In general, the legislation has increased market competition and encouraged the production and use of natural gas. The initiatives have also affected transportation and distribution patterns.

This chapter discusses the legislative and regulatory actions and their impact on the role of natural gas in the U.S. energy balance during the period from 1988 through 1994. Special attention is paid, where appropriate, to the effects that legislative and regulatory actions have had on gas transportation patterns and rates. The complex interrelations in the influences of different Federal and State actions and other market developments preclude the precise measurement of the effects of individual Federal regulation and legislation. Nonetheless, the direction of the impact is noted in the present chapter and estimates of the cumulative impacts of Federal actions are provided and discussed in later chapters. The chapter concludes with a discussion of action plans proposed by the Clinton Administration and emerging regulatory issues.

Industry Restructuring Under the Federal Energy Regulatory Commission

FERC has pursued a comprehensive program to create a flexible regulatory framework for the domestic natural gas industry since the mid-1980's (Table 1). FERC's key objectives are as follows:

- Provide for more extensive service options
- Enable parties to respond quickly to fast-changing market conditions
- Maintain service reliability and rate certainty.

The transformation of the natural gas industry to more open and flexible gas markets began with the issuance of FERC Order 436. This order, issued in 1985, *encouraged* interstate pipeline companies to separate their sales and transportation functions, therefore providing gas purchasers and producers more options for trading natural gas.

FERC Order 500, issued in 1987, clarified key issues that remained after Order 436 and created a mechanism for pipeline companies to recover from their customers the costs of modifying or terminating their long-term contracts with producers. Despite these changes, the pipeline companies retained a competitive advantage over producers because they could combine transportation, storage, and other services, and thus provide more reliable service. Order 636, issued in 1992, sought to remove the pipeline companies' competitive advantage by *requiring* them to unbundle their services, that is, to sell gas, transport gas, and provide other services separately (usually under separate subsidiaries).

Table 1. Significant FERC Orders Affecting Interstate Pipeline Companies, 1985-1994

Order	Effect of Order
1985, Order 436	Authorized blanket certificates for interstate pipeline companies if they offered open access transportation on a first-come, first-served basis. The order encouraged the unbundling of sales and transportation.
1987, Order 500	Modified Order 436 to address pipeline companies' take-or-pay issues.
1988, Order 490	Allowed abandonment of first-sales contracts. Allowed pipeline bypass.
1988, Order 491	Interpreted Section 5 of the Outer Continental Shelf (OCS) Lands Act to require that OCS pipeline companies offer both firm and interruptible transportation on a nondiscriminatory, open-access basis. Also proposed to mandate blanket certificates for OCS pipeline companies, allowing them to engage in the transportation and sale of natural gas without a case-by-case review and approval by FERC.
1988, Order 493	Natural Gas Data Collection System. Inquiry into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipeline Companies.
1988, Order 509	Interpretation of, and Regulations Under, Section 5 of the Outer Continental Shelf Lands Act Governing Transportation of Natural Gas by Interstate Pipeline Companies on the Outer Continental Shelf. Required that jurisdictional OCS pipeline companies provide open and nondiscriminatory access to both owner and nonowner shippers of natural gas.
1989, Order 500H	Finalized version of Order 500, modifying take-or-pay issues.
1989, Order 512	Removal of Contract Duration and Right of First Refusal Regulations for Certain OCS Gas. Offshore gas was previously sold to pipeline companies under long-term contracts of 15 years. This order removed that provision.
1990/91 Orders 528 & 528A	FERC's response to a ruling by the D.C. Court of Appeals that the method of recovering take-or-pay costs contained in Order 500 was unlawful. FERC's order caps recovery of take-or-pay costs through volumetric surcharges charged by pipeline companies.
1991, Order 537	Clarifies the authority of interstate pipeline companies to move gas "on behalf of" distributors or intrastate pipeline companies under NGPA Section 311. Section 311 transactions do not require blanket certificates if they pass certain FERC conditions.
April 8, 1992 Order 636	Requires pipeline companies to provide open-access transportation and storage, and to separate sales from transportation services completely. Mandates capacity release, electronic bulletin boards, and straight fixed-variable (SFV) rate design.
August 3, 1992 Order 636-A	Revises Order 636 provisions affecting small customers. Requires 10 percent of transition costs to be allocated to interruptible customers and requires pipeline companies to consider mitigating cost shifts resulting from change to SFV rate design.
November 27, 1992 Order 636-B	Denies further rehearing of Order 636 but clarifies many details. Reemphasizes the need to mitigate cost shifts from the switch to SFV rate design.
May 1994, Order 563A	FERC consolidated its requirements for standardized electronic bulletin boards and downloadable files.
May 27, 1994	FERC issued several orders clarifying the commission's gathering policy. FERC retains the right to disregard the separate corporate structures of the pipeline company and its gathering affiliate in the event that a pipeline company abuses the pipeline-affiliate interrelationship.

Source: Federal Energy Regulatory Commission.

FERC Order 436 (1985)

In October 1985, FERC issued Order 436, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol.* This was the first major step in a series of orders, including FERC Order 500 and FERC Order 636, that fundamentally restructured the gas industry, changing the relationships between producers, interstate pipeline companies, and customers. Specifically, Order 436 provided incentives for interstate pipeline companies to transport third-party gas. The order offered pipeline companies blanket certificates, if they would be willing to operate as open-access transporters. Under the blanket certificate, a pipeline company would have authority to engage in a broad range of transportation arrangements with shippers without the need to obtain prior authorization from FERC. In return for the blanket certificate, the pipeline company had to transport gas for any shipper and treat them no less favorably than they treated the movement of their own gas. Participating pipeline companies had to allow their customers to convert their contracts from entitlements for gas purchases to equivalent levels of transportation service over a 5-year period.

FERC Order 436 led only to partial restructuring of the industry because interstate pipeline companies were only encouraged, and not mandated, to provide open-access service. However, all major and most minor interstate pipeline companies agreed to provide open-access service. In addition, although Order 436 required participating pipeline companies to provide transportation service without discrimination or preference (regarding the source of the gas being transported), it did not address other key elements of pipeline companies' service to customers. For example, Order 436 did not provide similar incentives for pipeline companies to provide open access to storage facilities.[1]

Order 436 resulted in customers buying less gas from pipeline companies. However, the pipeline companies were still liable to pay producers for previously contracted gas supplies that they no longer wished to purchase. To address this problem, FERC issued Order 500 which enabled pipeline companies to recover up to 75 percent of the cost of modifying or terminating their long-term contracts from their suppliers. To date, pipeline companies have filed with FERC to reflect such payments to producers of about $10 billion.

[1]The lack of corresponding access to storage became of increasing concern for pipeline customers purchasing their own supplies and contracting separately for transportation.

FERC Order 500 (1987-1989)

FERC issued Order 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, in 1987. The intent of Order 500 was to maintain the progress toward open access to transportation service initiated in Order 436 while also addressing the concerns expressed by the United States Court of Appeals in it decision on appeal of Order 436. Order 500 modified Order 436 in certain key respects to accomplish the following:

- Minimize the pipeline companies' liability arising from provisions in contracts signed during earlier periods of perceived supply shortages that required pipeline companies to pay for gas even if they did not need it (take-or-pay provisions).

- Establish provisions for the passthrough of these take-or-pay costs to customers other than through a general rate case. The order required pipeline companies to absorb between 25 percent and 50 percent of these costs in order to be allowed to direct bill a portion of these costs.

- Adopt principles for levying gas inventory charges by pipeline companies to allocate risks and costs of maintaining ready supplies of gas for customers' use.

The ultimate effect of FERC Orders 436 and 500 was to encourage pipeline companies to provide transportation service on a nondiscriminatory basis, without favoring their own merchant subsidiaries over any third party. The orders began to separate the availability of transportation service from the use of the pipeline companies' merchant functions and facilitated direct sales from producers to customers. This allowed producers to bargain directly with end users, local distribution companies, and marketers, as well as with pipeline companies. By permitting these direct sales, the orders also provided producers with an outlet (the spot market) for gas the pipeline companies could not or would not buy.

Order 500 was revised a number of times to meet concerns from interested parties and was finalized in 1989 when FERC issued Order 500J. This order basically modified the take-or-pay crediting regulations established in Order 500 by essentially pushing forward the final date for the passthrough of costs from take-or-pay liabilities.

FERC Order 636 (1992)

FERC Order 636, known as the Restructuring Rule, was issued on April 8, 1992, and was designed to allow more efficient use of the interstate natural gas transmission system by fundamentally changing the way pipeline companies conduct business. Whereas previous orders had encouraged pipeline companies to provide transportation service on a nondiscriminatory basis, without favoring their own source of supply, Order 636 required interstate pipeline companies to unbundle, or separate, their sales and transportation services. The purpose of the unbundling provision was to ensure that the gas of other suppliers could receive the same quality of transportation services previously enjoyed by a pipeline company's own gas sales. This increased competition among gas sellers and diminished the market power of pipeline companies. The order includes the following major provisions:

- Required pipeline companies to provide open-access transportation service
- Encouraged the use and development of market centers
- Required pipeline companies to provide customers with open access to storage
- Established a capacity release market in transportation and storage capacity by allowing release of unwanted firm capacity
- Required pipeline companies generally to alter their rate structure to recover all fixed costs by a straight fixed-variable rate design
- Required pipeline companies to offer a new "no notice" firm transportation service if they provided bundled citygate firm sales service on May 18, 1992.[2]

Major Provisions

Open-Access Transportation. Order 636 required pipeline companies to provide open-access transportation services that are equal in quality whether the gas is purchased directly from the pipeline company or elsewhere, such as from a producer or a marketer. This increased wellhead competition in the industry as all gas merchants were afforded equal transportation opportunities and services.

Development of Market Centers. Order 636 encouraged the use and development of market centers where several pipeline systems interconnect and where many buyers and sellers can make or take gas deliveries. Market centers increase purchasing and selling opportunities, increase the reliability of gas supplies, and promote the exchange of pricing information.

To function effectively, a market center must exhibit two key characteristics. First, many buyers and sellers must have access to and participate in the market activities at the center, preventing any one buyer or seller from exerting excessive market power. Second, there must be a hub manager capable of physically matching buyers and sellers. One or several pipeline companies could manage the hub by using electronic information and control systems to arrange transactions. Market centers have developed in locations where several pipelines come together near large production and storage fields. For example, the Henry Hub near Erath, Louisiana, and the Katy, Texas, market centers have developed around the facilities of 28 and 23 pipeline companies, respectively.[3] (See Chapter 3 for additional discussion on market hubs.)

To facilitate the development of market centers, FERC encouraged pipeline companies to charge mileage-based rates rather than postage-stamp rates. Mileage-based rates are charged based on the distance over which gas is transported, while postage-stamp rates are charged for gas transported through a given area or zone, regardless of distance. FERC reasoned that mileage-based rates are appropriate for long-distance carriers, while postage-stamp rates are appropriate for grid systems.[4]

Open-Access Storage. Natural gas storage is integral to the efficient and reliable distribution of natural gas in the United States. Storage provides the means to supply consumer needs at times when their requirements exceed total gas production and mainline transmission capability. This typically happens during periods of cold weather. FERC Order 636 addressed underground storage specifically with key provisions that required unbundled and expanded access to interstate storage capacity. Under Order 636, most interstate storage became open access, with up to 90 percent of it now available to gas transportation customers.

Capacity Release. Capacity release is an example of the new flexibility in transporting gas provided by Order 636. Capacity release is the permanent or temporary resale of the rights to firm transportation and storage capacity on an open-access pipeline. A replacement shipper may also re-release capacity if permitted by the terms of the initial release. This retrading of capacity effectively establishes a secondary market in pipeline capacity that is intended to increase efficiency in gas transportation by reallocating capacity to shippers who value it most. Also, pipeline companies benefit from the higher utilization of their systems and from the fact that releasing pipeline capacity can offset the need to build new facilities. While the capacity release market has grown, impediments to its ease of use have caused

[2]No-notice service is a pipeline delivery service that allows customers to receive gas on demand up to their maximum contract level without making prior nominations to meet peak service needs.

[3]Federal Energy Regulatory Commission, Office of Economic Policy, "Importance of Market Centers" (Washington DC, August 1991), p. 7.

[4]On a "grid" system, there is no direct correlation between cost and distance because gas flows in multiple directions throughout the system, with gas received into the system from multiple entry points.

some shippers to use other avenues to dispose of their excess capacity.

To help the capacity release market develop, FERC required pipeline companies to establish electronic bulletin boards (EBB's) to provide shippers with equal and timely access to information about the availability of service on their systems. The EBB's were to include information on capacity available through release transactions and firm and interruptible capacity available directly from the pipeline.

Capacity release grew three-fold between the 5-month 1993-94 heating season and the 1994-95 heating season. The amount of capacity held by replacement shippers during the 1994-95 heating season more than doubled to 1,592 billion cubic feet, compared with 767 billion cubic feet held during the 1993-94 heating season. Releasing shippers were credited approximately $570 million in gross revenues from capacity release transactions during the period November 1, 1993, through March 31, 1995. Despite this growth, transportation of gas via released capacity remains a relatively minor portion of total pipeline throughput. [5]

Rate Design. A controversial provision of Order 636 was the redesign of pipeline companies' transportation tariff rates.[6] At stake was how the costs of providing transportation service should be apportioned among customers in light of FERC's goal of promoting competition among natural gas suppliers. To achieve this goal, Order 636 required pipeline companies to recover the majority of fixed costs associated with transportation service only through the capacity reservation fee charged to firm customers.[7] Firm customers are charged a reservation fee on a monthly basis to reserve daily capacity, based on their peak-period requirements. Interruptible customers do not reserve daily capacity and are not charged a reservation fee. Variable costs are recovered through a usage fee applied on a volumetric basis to the gas actually transported.

The new rate design, straight fixed-variable (SFV), was intended to help promote competition among gas suppliers by eliminating any price distortions inherent in the previously used modified fixed-variable (MFV) rate design and also to encourage the more efficient use of the pipeline system. Under the MFV rate design, certain fixed costs, such as return on equity and related taxes, were allocated to a commodity (usage) charge. This charge was levied on a per unit basis and applied to the volume of gas actually used, thus affecting costs for firm and interruptible customers alike.

The fundamental significance of the switch to SFV rate design is that firm customers are responsible for most fixed costs.[8] In some cases, this has resulted in increased transportation rates for low-load-factor customers,[9] who have highly seasonal demand with low overall levels of capacity usage over which to spread the cost impact. Many high-load-factor customers, such as industrial users who take relatively constant amounts of gas, and particularly interruptible customers, have seen their rates decline. (See box on p. 8.)

Some consumer groups, local distribution companies (LDC's), and other interested parties opposed the implementation of SFV rate design in large part because it was thought to increase costs greatly to low-load-factor customers. FERC developed a system of cost mitigation to address concerns that pipeline restructuring would unfairly burden some smaller customers. Cost mitigation plans were to spread the cost shifts over a period of up to 4 years.

The General Accounting Office estimated that without cost mitigation measures, about $1.2 billion in costs could be shifted annually from customers with interruptible service to customers with firm service.[10] As a result, firm customers would pay about 76 percent of the pipeline companies' annual total fixed cost of $11.4 billion, an increase over the 65 percent they were estimated to pay under the MFV rate design. The Energy Information Administration estimated that without cost mitigation, under SFV, transportation rates for a sample of six pipeline companies serving the East Coast would increase between 40 and 73 percent for low-load-factor customers,

[5]Electronic bulletin board data were supplied by Pasha Publishing. Inc. Revenues were estimated by the Energy Information Administration, Office of Oil and Gas, using transactions with complete information concerning the rate charged, charge type, capacity amount, and release duration. Such transaction data account for 95 percent of the 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.

[6]Transportation tariff rates are the maximum allowable rates, from which discounts may be granted by the pipeline company in order to compete effectively.

[7]Some fixed costs are recovered from interruptible customers to the extent that market conditions allow.

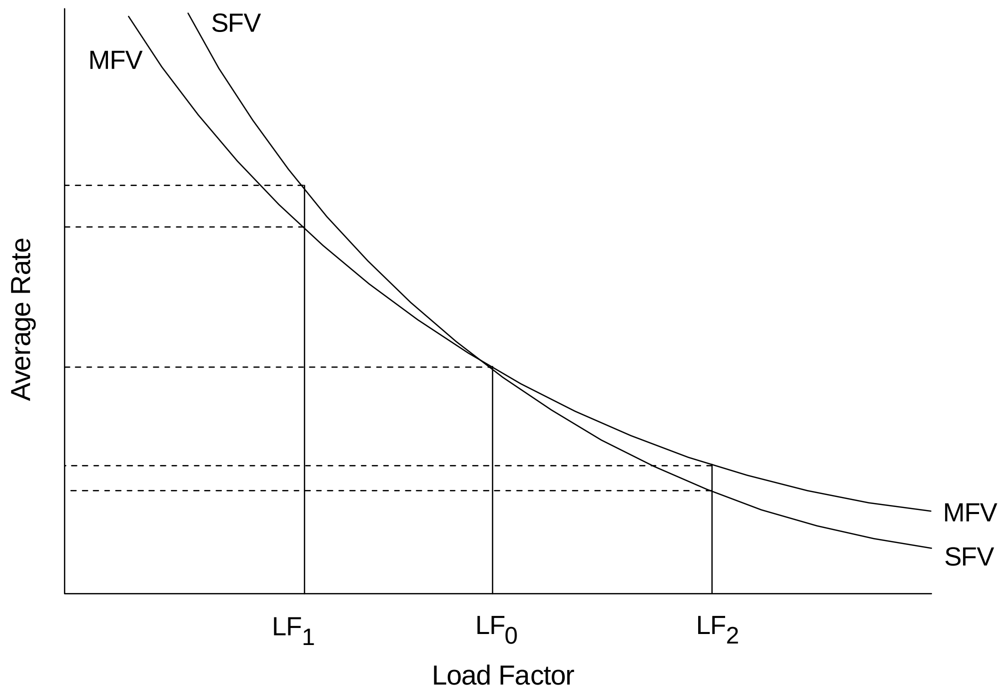
[8]In some cases, pipeline companies may have to forego recovery of some fixed costs by discounting costs from the maximum allowed rate in order to compete in the market.

[9]However, Order 636 provided for the continuation of one-part rates for small, low-load-factor customers who historically only paid for the service they would use.

[10]Government Accounting Office, "Costs, Benefits, and Concerns Related to FERC's Order 636," GAO/RCED-94-11 (November 1993), p. 6.

The Influence of Rate Design on Pipeline Customers

This diagram depicts the relationship between the load factor and the average rate under modified fixed-variable and straight fixed-variable allocation and rate design methods. Under both rate structures, increases in the load factor lead to a decline in the average rate. However, the rate of decline is more rapid under SFV than MFV. The average rate at a certain load factor is the same under both rate designs (depicted here at LF_0). Customers with a load factor below LF_0 (for example, at LF_1) face higher average rates under SFV than MFV, while customers with a load factor exceeding LF_0 (for example, at LF_2) have lower average rates under SFV than MFV. Consequently, high-load-factor customers are expected to benefit from SFV, while low-load-factor customers are exposed to higher average rates as a result of the switch to SFV from MFV.



MFV = Modified fixed-variable
SFV = Straight fixed-variable

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

whereas rates would decrease between 1 and 14 percent for high-load-factor customers.[11]

The move to SFV rate design may lead to a more optimal use of the existing pipeline network. Under MFV rate design some fixed costs of gas transportation were allocated to the usage fee. Therefore customers requiring firm service would not bear as much of the fixed costs of transportation as under SFV rate design. Increasing the reservation charges on firm service customers may help ration capacity in that the higher unit cost for reserving capacity should encourage more selective use of this level of service. In fact, the switch to SFV with its higher rates for low-load-factor customers likely contributed to the increased use of storage. The higher costs motivate customers to rely more on storage to assure deliverability.

[11]Energy Information Administration, *Natural Gas 1992: Issues and Trends*, DOE/EIA-0560(92) (Washington, DC, March 1993).

Other Issues

Transition Costs

FERC recognized that pipeline companies would incur costs as a result of complying with Order 636. These costs fall into four categories:

- Gas supply realignment costs resulting from pipeline companies reforming or buying out existing gas supply contracts or continuing to perform under certain contracts

- Unrecovered gas costs remaining when a pipeline company closes out unpaid balances on gas supplies that it previously sold to its customers

- Stranded costs representing assets previously used to provide bundled sales service (such as the pipeline company's own facilities, gas in storage, and capacity on upstream pipeline companies) that cannot be directly assigned to customers of the pipeline company's unbundled services

- Costs incurred to purchase new equipment, such as gas metering and electronic bulletin boards.

Initially, Order 636 specified that the pipeline companies would be permitted recovery of 100 percent of their "prudently incurred" transition costs in the form of reservation surcharges to customers, or from an exit fee charged to firm-service customers.

Many LDC's, State commissions, and consumer advocates found fault with the transition cost recovery provision in Order 636. They argued that the 100-percent passthrough of realignment costs would place undue burdens on captive customers of the LDC's, whereas pipeline companies, producers, marketers, and industrial consumers would not pay their share. Partly in response to such objections, FERC issued Order 636-A on August 3, 1992, which requires pipeline companies to recover 10 percent of the cost of changing supply contracts through their rates for interruptible transportation under their Part 284 blanket certificates.

Most pipeline companies have provided estimates of transition costs to FERC. As of the implementation of FERC Order 636, estimates of transition costs were about $4.8 billion.[12] By September 30, 1994, pipeline companies had filed for $2.1 billion in transition costs, including $1.1 billion of gas supply realignment costs, $572 million of unrecovered gas costs, and $420 million of stranded costs.[13] By August 1995, $2.7 billion in total transition costs had been filed for approval by FERC.

The restructuring of the natural gas industry that began with Order 436 and was substantially completed with Order 636 has changed gas transportation patterns and rates. Increased competition among gas suppliers fostered by the new market flexibility has generally exerted a downward pressure on wellhead gas prices. Competition among pipeline companies and the move to SFV rate design have significantly changed transportation rates in some regions. (See Chapter 4 for additional discussion of pipeline rates). Greater competition at the citygate and increased opportunities for purchasing natural gas have placed downward pressure on end-use prices. This has contributed to changes in regional production, transportation, and consumption patterns, and to greater efficiency in the use of the gas industry infrastructure.

Costs associated with the restructuring of the natural gas industry will continue to affect transportation rates and prices paid by consumers. These costs are expected to have an impact on delivered prices through the late 1990's. The extent of the impact is being influenced by the cost shift mitigation procedures required by Order 636, by State regulatory actions, and by company actions.

FERC Jurisdiction over Gas Gathering

Under industry restructuring, many pipeline companies have been selling, or spinning down, their gathering facilities to affiliates that are unregulated by FERC, while other facilities have been spun off to nonaffiliates.[14] FERC regulated gathering rates when gathering was bundled with transmission, but FERC's jurisdiction is less clear when gathering is offered as an unbundled service by an unregulated pipeline subsidiary. On May 27, 1994, FERC issued several orders clarifying its gathering policy. In the orders, FERC determined that it generally does not have jurisdiction over gathering affiliates of interstate pipeline companies. However, FERC retains the right to disregard the separate corporate structures of the pipeline company and its gathering affiliate in the event that a pipeline company abuses the pipeline-affiliate relationship.

Prior to Order 436, pipeline companies had generally included gathering costs in their rates for bundled, citygate sales service. When FERC began its initiatives to create a nondiscriminatory,

[12]Government Accounting Office, *Costs, Benefits, and Concerns Related to FERC's Order 636*, GAO/RCED-94-11 (November 1993), p. 62.

[13]Federal Energy Regulatory Commission, *1994 Annual Report* (Washington, DC, May 1995), p. 5.

[14]Spindowns are a transfer of facilities to a pipeline company affiliate. Spinoffs are a transfer of facilities to an entity that is not affiliated with the pipeline company.

open-access transportation market, it recognized the need for conditions to ensure strict differentiation of pipelines' gathering costs from transmission costs. Accordingly, Order 436 required open-access pipeline companies to identify separately the cost components of their rates attributable to transportation, storage, and gathering costs. In Order 636, which mandated the complete unbundling of interstate pipeline sales and transportation services, FERC expressed its strong preference for fully unbundled gathering rates. Some producers are concerned that gatherers enjoy a monopoly in many situations and have complained to FERC and State regulatory bodies about rising rates. Some States are looking into playing a greater role in regulatory oversight of gathering rates where there are clear anticompetitive forces at work.

Market-Based Rates

Many of the risks in the interstate pipeline industry change by moving away from the traditional cost-of-service rate structure to market-based rates. Under the cost-of-service approach, rates are set at a level that is expected to generate enough revenues to allow the company to recover its expenses plus an allowed return on assets. However, these rates do not necessarily reflect relative value of the service to the firm customers. As a result of the shortcomings of cost-of-service rates, FERC has begun to consider alternative methods for establishing rates for pipeline services. Incentive rates, one alternative, are designed to simulate competition in a monopoly environment by tying pipeline company returns to performance. In October 1992, FERC issued a policy statement on incentive ratemaking, establishing guidelines for companies to use in formulating incentive proposals.

FERC approved market-based rates for new storage facilities for several companies in 1993 and 1994. In 1995, FERC issued a staff paper that evaluated the potential for market-based rates for pipeline services and sought public comments on the paper as well as on other nontraditional ratemaking methods. The reactions of the industry to the FERC initiatives have differed depending on the industry segment. LDC's are generally opposed to market-based rates for firm transportation because they perceive that markets are not yet truly competitive.

Incremental vs. Rolled-In Rates

The issue of who should pay for pipeline capacity expansions and how the rates should be structured has been a subject of debate among interested parties during the past few years. At issue is whether the cost of a pipeline expansion should be borne only by pipeline customers who will directly benefit from the expansion (incremental rates), or whether a pipeline company can spread the cost of providing the new service over all its customers (rolled-in rates). This has been a contentious issue, which has been blamed for slowing pipeline capacity expansion projects.

On May 31, 1995, FERC issued its "Pricing Policy for New and Existing Facilities Constructed By Interstate Natural Gas Pipelines." The principal goals of this policy are to provide the industry with as much up-front assurance as possible with respect to the rate design to be used for an expansion project, while, at the same time, providing for a flexible assessment of all the relevant facts of a specific project. The policy has two major features. First, in the future FERC will make a determination of an appropriate rate design in a pipeline company's certificate proceeding. Second, when the pipeline company seeks rolled-in pricing, FERC will base its pricing decision on an evaluation of the system-wide benefits of the project and the rate impact on the existing customers.

Recently, FERC further clarified its position on rolled-in versus incremental rates, and issued new guidelines on how pipeline companies should recover costs of expansion. FERC took a flexible approach that evaluates the rate structure on a case-by-case basis. If a pipeline company can show that there will be system-wide benefits from a proposed expansion and that rates to existing customers will rise no more than 5 percent, rates can be rolled-in. Otherwise, incremental rates would be applied. These would probably be mitigated, for example, by collecting part of the rates from expansion shippers on an incremental basis and part on a rolled-in basis. The precedent set by the new ruling should make it easier for pipeline companies to add capacity because additions can be approved more readily, and with more certainty, for lower average transportation fees compared to incremental rates. This will improve the marketing opportunities for the new capacity, thus enhancing its economic attractiveness as an investment.

Special Rates

To facilitate gas use by the electric industry, in certain instances FERC has authorized levelized transmission rates and other special rate schedules for gas shipped to electric generators. In recent proceedings, FERC authorized several pipeline companies to serve electric generators using incremental rates, e.g., Algonquin Gas Transmission Corporation for Canal Electric Company. Also, FERC recently approved a special rate schedule for Tennessee Gas Pipeline Company to ship gas for electric generation customers. The special rate schedule was designed to satisfy electric companies' unique operational characteristics arising from their gas demand patterns. Further, FERC is currently considering additional measures that would tend to facilitate growth in gas usage by electric generators. These include a proposal by Tennessee Gas Pipeline Company to implement fixed-price contracts. Such rate certainty makes gas a more attractive commodity for electric generators when choosing fuels.

Significant Policy Initiatives and Legislation

A major objective of energy policymakers is to provide the regulatory and legislative framework that will ensure adequate energy supplies and also protect environmental quality. Recent legislation and policy initiatives have significantly altered factors affecting supply and demand and will continue to influence the development of gas markets into the next century (Table 2).

Repeal of the Power Plant and Industrial Fuel Use Act (1987)

The goal of ensuring an adequate supply of energy and protecting the environment is highlighted by the repeal of the Power Plant and Industrial Fuel Use Act (FUA-Public Law 95-620, 1978). The repeal of this Act provided increased market opportunities for natural gas in the electric generation industry and other major industrial customers.

The FUA, requiring major industrial facilities to use fuels other than oil and natural gas, was passed in response to perceived oil and gas shortages during the 1970's, and had the effect of significantly dampening gas demand. In response to a significant oversupply of gas that persisted through most of the 1980's, the Act was amended in 1987 to repeal sections that restricted the use of natural gas by industrial users and electric utilities. Specifically, the Act:

- Repealed restrictions on the use of natural gas and oil by large new baseload electric power plants
- Lifted restrictions on major-fuel burning installations, including large industrial boilers, turbines, and engines
- Continued the exemption from natural gas consumption restrictions for industrial cogenerators that run more than 3,500 hours annually and sell more than 50 percent of their electricity into the grid
- Lifted effective restrictions on all new facilities constructed after 1987.

The repeal of FUA allowed new industrial consumers and electric utilities to build large new gas-fired facilities.

U.S.-Canadian Free Trade Agreement (1988)

The U.S.-Canadian Free Trade Agreement of 1988 was a major step toward eliminating barriers to trade between the United States and Canada. The energy provisions of this agreement prohibited most import and export restrictions on energy products. Prior to this agreement, Canadian producers had to meet a number of criteria before they would be authorized to export gas to the United States. The agreement provided for the specific elimination of taxes on energy imports and exports, the removal of bilateral tariffs, and an end to price discrimination. However, the agreement also:

- Allowed either country to restrict exports to respond to supply shortages, to maintain a domestic price stabilization program, or to enact resource conservation measures. Export restrictions are allowed only if they do not reduce the proportion of total supply historically available to the other country and do not impose a higher price on exports than on domestic sales
- Allowed the creation and continuation of government subsidies and incentives for natural gas development.

Natural gas imports from Canada rose from 1.3 trillion cubic feet in 1988 to 2.6 trillion cubic feet by 1994. The U.S.-Canadian Free Trade Agreement certainly is an important factor in this growth in crossborder trade. However, the agreement was preceded by two actions by the Canadian government that may be considered at least as important to increasing U.S. imports of Canadian gas since 1988. First, the *Agreement on Natural Gas Markets and Prices* (October 31, 1985) furthered a more market-oriented pricing policy for gas exports, which allowed Canadian sales to be more competitively priced than was the case under the Volume Related Incentive Pricing Program. Second, the National Energy Board in 1987 adopted the "Market-Based Procedure" as the surplus determination procedure for export authorization. Adoption of this less restrictive standard provided the opportunity for increased gas export sales.

Increased imports have placed downward pressure on wellhead prices in the lower 48 States and increased competition among U.S. producers. Transportation patterns have changed with a greater share of natural gas transported from Canada to the Northeast and Midwest.

Table 2. Major Legislation and Policies Affecting the Natural Gas Industry, 1987-1994

Law/Policy	Effect of Law/Policy
1987, Repeal of the Power Plant & Industrial Fuel Use Act	Ended restrictions on natural gas use by electric utilities and large industrial users.
1988, U.S. Canadian Free Trade Agreement	Ended legal barriers to trade in gas between the United States and Canada.
1989, The Natural Gas Wellhead Decontrol Act	Phased decontrol of wellhead prices.
1990, Clean Air Act Amendments of 1990	Required significant changes in gasoline composition for air-quality attainment and special programs for California vehicles; tightened restrictions on the release of hazardous pollutants; established tougher emission standards for most offshore drilling.
1990, Revenue Reconciliation Act	Extended unconventional gas tax credits to tight sands and the date for the expiration of the credit to January 1, 1993.
1992, Energy Policy Act	Encourages the development of clean-fuel vehicles; encourages energy conservation and integrated resource planning; gives alternative minimum tax relief to independent producers; and exempts "exempt wholesale generators" (EWG's) from regulation under the Public Utility Holding Company Act.
1992, North American Free Trade Agreement	Joins the United States, Canada, and Mexico into largest trading block in the world. Despite only limited concessions regarding the natural gas industry by Mexico, it is likely to have a positive impact on industry development and trade.
1993, The Climate Change Action Plan	Developed three policy initiatives to reduce emissions of greenhouse gases to their 1990 levels by the year 2000: increase the natural gas share of energy use; promote the summer use of natural gas in electric utility coal- and oil-fired plants, and in industrial facilities to reduce NO_x emissions; and commercialize high-efficiency gas technologies.
1993, The Domestic Natural Gas and Oil Initiative	Contains explicit measures intended to enhance the efficiency and competitiveness of U.S. industry, and reduce the trend toward higher energy imports. The initiative addresses issues such as tax policy, advanced drilling technologies, cost of regulation, and market demand.

NO_x = Nitrogen oxides.
Sources: The U.S. Congress, the Clinton Administration, and the U.S. Department of Energy.

The Natural Gas Wellhead Decontrol Act (1989)

The Natural Gas Wellhead Decontrol Act of 1989 (Public Law 101-60) established a schedule to remove price controls on wellhead sales of natural gas. More than 40 years of wellhead price controls on interstate supplies ended on January 1, 1993. The full decontrol of wellhead prices is the final phase of price decontrol that began with the Natural Gas Policy Act of 1978 (NGPA).

Price ceilings established for different categories of natural gas under the NGPA had created severe distortions in the gas market and significantly influenced producers' drilling decisions. For example, a high-price ceiling for gas produced from wells drilled in deep formations created a drilling boom for high-cost deep gas in the early 1980's. Price controls meant that producers did not always seek the most gas at the lowest cost, but sought gas that brought the highest price in the regulated market. The Wellhead Decontrol Act removed the price ceilings that remained under the NGPA, which had the effect of increasing supplies from the most cost-effective sources, therefore increasing overall U.S. gas supplies while lowering gas prices. Since gas now tends to be produced from the lowest cost deposits, regional transportation patterns have been altered with more supplies moving from low-cost recovery areas. The need to build new pipeline capacity to service any new flows could affect customer rates in the future.

Clean Air Act Amendments of 1990

Among the most significant recent changes in environmental law were the Clean Air Act Amendments of 1990 (CAAA, Public Law 101-549). Only two prior clean air legislative efforts are comparable in magnitude—the Clean Air Act of 1970 (Public Law 91-604) and the 1977 Clean Air Act Amendments (Public Law 95-95). The 1990 Amendments contain seven separate titles covering different regulatory programs. They create new regulatory requirements to install more advanced pollution control equipment and to make other changes in industrial operations and even community lifestyle that will lead to reductions in emissions of air pollutants. Although the 1990 Amendments significantly alter and add to the regulatory requirements of the Clean Air Act, the basic framework and procedural aspects of the Act have remained as established by the 1970 Act and 1977 Amendments.

The purpose of the CAAA is to set standards to improve air quality and to curb acid rain. The amendments promote the control of ozone and sulfur emissions and the use of clean-fuel vehicles. The amendments are expected to lead to increased use of natural gas by electric utilities and to expand its commercial use in vehicles. More stringent air quality standards on offshore drilling in certain regions will adversely affect natural gas supplies. The CAAA, however, does not address carbon emissions; limits on carbon emissions would likely lead to additional gains for natural gas in the competition with coal for the electric utility market.

The CAAA generally is expected to result in increased natural gas demand as gas consumption should help many energy consumers meet the requirements of the CAAA. For example, the CAAA subjects NO_x to stringent controls; no new source of NO_x emissions can be built in areas that have not attained prescribed air quality standards for ozone. In addition, existing sources of pollution must install reasonably available control technology (RACT) to lessen the emissions. Depending on the severity of the pollution, nonattainment areas must come into compliance with national air quality standards over 3 to 20 years. The actual procedures for attaining the prescribed air quality standards are left to the States and thus the emphasis on control differs in various areas of the country. The upper Midwest and the New England areas are expected to use more gas-fired generators to produce electricity, while California is expected to continue leading the Nation in the use of natural gas-fueled vehicles. Natural gas pipeline companies are subject to additional costs where the pipeline crosses a nonattainment area since pipeline compressor stations, which burn gas, are a source of NO_x.[15]

[15]On average, compressor stations emit just over 1,000 pounds per million cubic feet of pipeline fuel use on average, although values for individual stations vary widely.

Electric Utility Use. The CAAA aims to decrease acid rain by reducing sulfur dioxide (SO_2) and NO_x emissions from electric utilities. Phase I of the CAAA, 1995 through 1999, targets the power plants with a nameplate capacity of 100 megawatts or more that emit 2.5 pounds or more of SO_2 per million Btu of energy consumed. The Act lists by name 110 such plants. The CAAA sets targets for emissions levels and specifies allowable emissions levels for each plant. If a plant does not meet the required emissions level, it is subject to a fine. If the plant performs better than the requirements, the plant can sell its allowance to a plant that needs additional allowances to cover its emissions.

Some existing electric utilities will probably increase their use of natural gas in order to lower their sulfur emissions. As the test for compliance is an annual one, the electric utilities can burn natural gas during nonpeak times and build up allowances for their own use or to sell to others.

Phase II of the amendments covers the period beginning in 2000. In this phase, emission levels are further lowered for the original 110 power plants and are extended to a broader group—all electric utility steam units of 25 megawatts or more. Again natural gas use should increase as utilities operate existing natural gas-fired units more frequently. In addition, some new capacity fueled by natural gas is expected to be built after 2000. However, because of the difference between the prices of coal and natural gas and the availability of long-term contracts for coal at relatively low prices, some additional capacity after 2000 is also expected to be coal fired.[16] Improved technology has made new coal-fired plants much less polluting, and pollution-control equipment that can be used on current plants, although expensive, has improved greatly. Electric utilities must consider control equipment costs when making decisions regarding capacity extensions or new construction. They also must decide quickly how they are to comply with Phase II requirements because of the long lead-time needed to build new capacity. According to a recent study published by the Energy Information Administration, *Performance Issues for a Changing Electric Power Industry*:

> At the end of 1993, utilities planned to build 28 new gas steam units and 250 gas-fired combustion turbines with a total net summer capability of 24.4 gigawatts by 2003. This represents 62 percent of the utility planned additions.[17] Natural gas has also increasingly been the major fuel used by nonutility electricity generators. In 1993, natural gas

[16]Energy Information Administration, *Annual Energy Outlook 1995*, DOE/EIA-0383(95) (Washington, DC, January 1995), p. 28.

[17]Energy Information Administration, *Inventory of Power Plants in the United States 1993*, DOE/EIA-0095(93) (Washington, DC, December 1994), Tables 1 and 4.

fueled more than half of all nonutility electric generation,[18] and gas consumption has been climbing steadily for several years.

Natural gas consumption by electric generators is expected to be one of the strong growth areas over the next 15 years. The Energy Information Administration, in its 1995 *Annual Energy Outlook*, forecast average annual growth of 2.8 percent between 1993 and 2010, with consumption increasing from almost 3 trillion cubic feet to 4.7 trillion cubic feet.

Transportation Use. The second major thrust of the CAAA was toward clean-fuel vehicles (CFV's). The CAAA requires automobile manufacturers, under a pilot program in California, to sell 150,000 CFV's a year starting in 1996 and 300,000 CFV's a year starting in 1999. It also requires some commercial fleets to begin buying CFV's between 1998 and 2001. These are fleets of 10 vehicles or more that are centrally fueled (or capable of so being) in 22 areas that have been designated as nonattainment areas for ozone and carbon monoxide. The aim is that, eventually, 70 percent of all covered fleets will be CFV's. The pilot program will first lead to reformulated gasolines and better catalysts. By 2001, more stringent standards for fleets nationwide and for cars in California are expected to lead to CFV's such as those fueled by natural gas. In its 1995 *Annual Energy Outlook*, EIA estimated that natural gas used in transportation would grow at an average annual rate of 26 percent between 1993 and 2010 .

More natural gas refueling stations are needed to enhance the viability of the switch to natural gas CFV's. At present, natural gas refueling is available at 930 stations, in 48 States and the District of Columbia. More stations are in the planning stages. Approximately two-thirds of these stations are owned by public utilities, with the rest either privately or publicly owned. More than half of the stations are accessible for public use.[19] In order to promote the availability of vehicular natural gas (VNG), FERC issued Order 543 on July 16, 1992, simplifying the certification process for VNG retail sales and minimizing the reporting requirements of VNG wholesalers.

Drilling Restrictions. The CAAA also affects oil and gas drilling on the Outer Continental Shelf (OCS). It requires that, except for the areas off the coasts of Texas, Louisiana, Mississippi, and Alabama, drilling sites within 25 miles of the coast must meet the same clean air requirements as onshore. These new standards will affect the leasing and drilling activities for both oil and gas because drilling can result in significant emissions. This new requirement, to be monitored by the Environmental Protection Agency, was to be met within 12 months of passage of the CAAA. The areas of the western Gulf of Mexico coastline have less stringent requirements and are administered by the Department of the Interior. The additional costs of complying with the CAAA are not expected to alter current regional supplies. However, the more restrictive requirements for areas other than the western Gulf likely will alter future supply development. In that sense, the CAAA may significantly affect future transportation patterns or rates.

The CAAA could have significant effects on future U.S. demand and supply levels and regional patterns, although impacts likely are limited at present. However, assuming that the Act continues the trend towards higher gas consumption, new pipeline capacity may have to be built to service new customers, which would probably in turn affect rates for existing customers.

Energy Policy Act of 1992 (Public Law 102-486, 1992)

Comprehensive energy legislation passed by Congress in October 1992 has expanded market opportunities for natural gas, although its emphasis on conservation and efficiency improvements also limits growth in some areas. The Energy Policy Act (EPACT) affects the natural gas industry in the following ways:

- Encourages conservation and energy efficiency by gas distributors, including demand-side management measures
- Protects natural gas imports and exports involving nations with which the United States has free trade agreements
- Gives a variety of financial incentives to developers and users (both public and private) of clean-fuel vehicles, such as natural gas-fueled vehicles
- Lifts Public Utility Holding Company Act (PUHCA) restraints on nonutility generated power
- Authorizes FERC to order electric utilities to transport electricity for other wholesale market participants
- Provides relief for independent producers from Alternative Minimum Tax preferences for percentage depletion and drilling costs.

[18] Edison Electric Institute, *1993 Capacity and Generation of Non-Utility Sources of Energy* (Washington DC, November 1994), p. 52.

[19] American Gas Association, "Policy and Analysis Issues, Issue Brief 1992-6" (Arlington, VA, July 2, 1992).

Energy Efficiency. EPACT contains several policies that are designed to improve energy efficiency. It builds upon successful programs by mandating energy performance standards and labeling programs for a host of products. The legislation also attempts to improve the efficiency of the Nation's electric utilities and the Federal power marketing agencies through implementation of integrated resource planning (IRP) and demand-side management (DSM) programs. Essentially, the IRP provisions encourage States to use incentive ratemaking practices that motivate utilities to use DSM and energy-efficiency measures to meet customer needs.

Alternative-Fueled Vehicles. The sections in EPACT that relate to alternative-fueled vehicles (including those fueled by gas) support the work begun by the CAAA in opening up new markets to natural gas. To provide incentives to manufacturers, it required the Federal Government to acquire at least 5,000 light-duty alternative-fueled vehicles in fiscal year 1993 and 17,500 more through 1995. The Federal Government is to continue purchasing alternative fueled vehicles so that 75 percent of its new vehicles will be in this category by 1999.

To encourage retailers and transporters of vehicular natural gas, the legislation states that those involved would not be regulated as natural gas companies unless they are engaged in other natural gas business. Federal assistance will also aid States in setting up plans to encourage the use of alternative-fueled vehicles. Some States already encourage the use of natural gas in vehicles by not taxing this use, while the Federal tax on natural gas used as a motor fuel is only 4 cents per gallon of gasoline equivalent, compared with 18 cents per gallon of motor gasoline in 1994.[20]

PUHCA Reform. Some other provisions of EPACT are having a major effect on the natural gas market, particularly through amendment of the Public Utility Holding Company Act (PUHCA) of 1935 (Public Law 74-333). PUHCA requires the registration of all public utility (gas and electric) holding companies. It was originally passed to regulate the interstate holding companies that, because of their size and complex organization, were able to escape state regulation. PUHCA limited holding companies to an integrated geographic area. These PUHCA amendments in EPACT are intended to stimulate power generation by nonutilities (eligible wholesale generators), many of which will use natural gas as their primary fuel.

The EPACT amendments to PUHCA[21] created a new category of generating company called "eligible wholesale generators" (EWG's), which were exempted from PUHCA regulation, and established conditions under which existing utilities would be able to own unregulated generation facilities. Under these amendments, the Securities and Exchange Commission has less financial oversight over decisions made by utilities. States and FERC have continued oversight, especially of rates and terms for power and transmission. When EWG's build new plants, they will most likely be gas turbines because of the lower up-front capital costs compared to large coal-fired plants.

The nonutility power producers have become an important part of the electric utility picture. Since 1983, nonutility's share of total U.S. generation has increased from barely 3 percent to more than 10 percent in 1993.[22] The growing number of nonutility power producers allowed electric utilities to obtain needed peak capacity while avoiding difficulties with construction lead times, environmental issues, prudence reviews, and disallowances. The success of these nonutility power producers has demonstrated that competitive entry into electric generation is a feasible alternative to regulation. As restructuring of the electric industry proceeds, EWG's should become a more significant source of power generation and could therefore increase gas demand.

Alternative Minimum Tax. EPACT repealed the Alternative Minimum Tax (AMT) for certain classes of smaller independent gas producers. The AMT requires that a corporation pay the greater of taxes computed from the regular corporate income tax system or taxes computed from the AMT. The impact of the repeal of AMT is to lower producers' costs, allowing them to bring cheaper gas to market.

Overall, EPACT should have a positive impact on gas demand and supply. However, this should be moderated somewhat by the provisions that encourage energy efficiency.

[20] Energy Information Administration, *Petroleum Marketing Annual 1994*, DOE/EIA-0487(94) (Washington, DC, August 1995), Table EN1.

[21] Prior to EPACT, PUHCA was altered by the Public Utilities Regulatory Policy Act of 1978 (PURPA, Public Law 95-617) that created incentives for Qualifying Facilities (QF), which are nonutility power producers who meet certain standards. A QF must (1) be a cogeneration facility or use waste or renewable energy sources; (2) be less than 50 percent owned by electric utilities; (3) if a cogeneration facility, have a thermal output of at least 5 percent of the total energy output; and (4) if oil- or gas-fired, meet an efficiency standard, that is, the electricity produced plus one-half of the thermal output must be no less than 42.5 percent of the energy content of the gas or oil used for fuel. When QF's were allowed to sell their excess power to electric utilities, other power producers also entered the market.

[22] Energy Information Administration, *Performance Issues for a Changing Electric Power Industry*, DOE/EIA-0586 (Washington, DC, January 1995), p. ix.

North American Free Trade Agreement (1992)

The North American Free Trade Agreement (NAFTA) forms the largest trading block in the world, with an economy of $6 trillion.[23] While the agreement eliminates many trade barriers during the next 15 years, it failed to incorporate the same provisions with regard to natural gas trade that are contained in the earlier U.S.-Canada Free Trade Agreement. Specifically, the Mexican government would not accept a "security of supply" clause whereby both Mexican consumption and exports would be curtailed in equal volumes in the event of a domestic shortage of natural gas. The Mexican government has intervened heavily in the past in natural gas exports and, under NAFTA, retains the right to curtail exports. Another point of contention during negotiations was the Mexican government's ownership, mandated by the Mexican constitution, of all segments of the domestic hydrocarbon industry, from reserves through production, transportation, and refining. Under NAFTA, the Mexican energy agency, Petroleos Mexicanos (PEMEX), retains ownership of all segments of the natural gas industry, but, as in the past, it may contract with foreign companies for services necessary to conduct its business. The only concession Mexico made with regard to natural gas was that foreign producers may sell their gas directly to end users in Mexico, but they must negotiate with PEMEX for transportation.

Despite these impediments to totally free trade in gas, in 1993 PEMEX began exporting natural gas to the United States for the first time in 9 years (just under 1 billion cubic feet in December 1993). At least three projects to increase crossborder capacity with Mexico have been proposed, which, if completed, would expand capacity by 583 million cubic feet per day. Legislation was passed by the Mexican Congress on April 29, 1995, which is intended to partly privatize the distribution, transportation, and storage of natural gas. These initiatives already have led to U.S. involvement in projects to develop regional pipelines and LDC's, along with gas-fired power plants in Mexico.[24] Significant changes to crossborder trade between the United States and Mexico likely will remain well in the future. It should be noted that exports of U.S. gas to Mexico rose from 1988 through 1992. After a temporary drop in 1993, Mexican receipts of U.S. gas are recovering despite devaluation of the peso. Thus, NAFTA appears not to have altered crossborder trade significantly at this point. However, the formal recognition of a North American market should ensure continued and most likely expanded trade in the long term.

[23]"U.S., Canada and Mexico Agree to Form Trade Block," *The Washington Post* (August 13, 1988), p. A1.

[24]"Mexico to partly privatize gas sector," *Oil and Gas Journal* (May 3, 1995).

Other Government Policies and Incentives

Energy legislation and government regulations have varying impacts on the natural gas industry. Certain regulations require oil and natural gas companies to consider the environmental impact of any exploration or production projects. Three areas of recently modified or developed environmental regulation will affect the natural gas industry. These three areas are the Outer Continental Shelf (OCS) drilling moratoria, wetlands policy, and the disposal of polychlorinated biphenyls (PCB) contaminated pipes. Two other recent legislative changes also will affect the industry: natural gas production incentives and the Pipeline Safety Act of 1992.

Offshore Moratoria. Of particular relevance to the natural gas industry is the continuation of congressional and presidential offshore oil and gas drilling moratoria along the Outer Continental Shelf (OCS). The OCS currently accounts for 25 percent of U.S. gas production, and an estimated 9.4 trillion cubic feet of the resource base is off-limits to drilling.[25] At present, drilling is prohibited along the entire U.S. East Coast, the west coast of Florida, the U.S. West Coast, except for an area off the coast of southern California, and the North Aleutian area of Alaska.[26] Although offshore moratoria have had little or no implication for regional transportation patterns and rates, should the offshore moratoria eventually be lifted, increased production could alter regional supply patterns and therefore transportation routes.

Wetlands Policy. A substantial part of natural gas resources is located in wetland areas, posing environmental concerns for the natural gas industry. Current legislation protects wetlands, and natural gas companies must consider current and potential wetlands legislation when drilling or producing gas. To drill on wetlands, natural gas producers must obtain permits from as many as five Federal agencies. At present, the wetlands restrictions mainly affect drilling along the coasts of Louisiana and Texas. If, in the future, the moratoria on drilling along the East Coast, the west coast of Florida, and the Alaska and California coasts are lifted, gas and oil producers will still have to contend with wetlands restrictions in those areas. Current regulation fails to distinguish between wetlands of high ecological value and those with marginal value. The Environmental Protection Agency (EPA) introduced a new wetlands protection policy that narrows the definition of

[25]U.S. Department of Energy, *Integrated Analyses Supporting the National Energy Strategy: Methodology, Assumptions, and Results*, DOE/S-0086P (Washington, DC, 1991/1992), p. 39.

[26]In Alaska, drilling is also prohibited in the Alaskan National Wildlife Refuge (ANWR). However, natural gas production from ANWR is a highly uncertain prospect that is not expected until well after 2000, if at all.

wetlands and establishes categories for wetlands based on ecological value.

Polychlorinated Biphenyls in Natural Gas Pipelines. Another environmental issue that must be addressed by the natural gas industry is polychlorinated biphenyls contamination. PCB's are poisonous environmental pollutants that can accumulate in animal tissue. The natural gas industry operates about 1.5 million miles of pipeline and thousands of compressor stations for interstate transmission or distribution systems. Although the EPA banned virtually all uses of PCB's by 1980, both pipelines and compressor stations can be sources of lingering contamination. Difficulties and expense arise from the disposal of PCB-contaminated natural gas pipeline and other equipment. PCB's can be found in pipeline liquids associated with the transmission of gas and can escape past the compressor seals. Costs associated with PCB cleanup has increased rates in several cases, although competitive pressures may limit the ability of pipeline companies to pass them through to customers.

Natural Gas Production Incentives. Production credits for unconventional gas were allowed under Section 29 of the Crude Oil Windfall Profit Tax Act of 1980. The credit was discontinued for wells drilled on or after January 1, 1993, although production from wells drilled before the expiration date qualify for the credit until January 1, 2003. Section 29 tax credits provided an incentive for the development of high-cost gas supplies by producers. The impact of the credit was most significant for gas produced from coal seams and tight formations. For example, under Section 29, a tax credit of approximately $0.95 per million Btu was available against production from coalbed methane wells drilled before January 1, 1993.[27] The credit's effect was dramatic, and coalbed methane drilling increased significantly between 1988 and 1992. Despite being in place since 1980, the credit seemed to have an increasingly strong impact as the expiration date neared. Drilling into coalbeds raised reserves to 10.0 trillion cubic feet by 1994. Coalbed methane production increased almost sixfold in just 3 years to account for 3 percent of U.S. gas production in 1992. The credit allowed producers of coalbed methane to underbid producers of conventional gas sources. Consequently, drilling resources tended to be allocated away from conventional gas prospects to coalbed methane prospects located mainly in New Mexico and Alabama. Moreover, the increase in production required the laying of new gathering facilities and connection to existing pipelines to gather and transport the gas.

The Pipeline Safety Act of 1992. This Act gave the Department of Transportation's Research and Special Programs Administration (RSPA) responsibility for implementing pipeline safety provisions that affect the natural gas industry. The Act will increase pipeline industry refurbishment costs, some of which would be passed on to customers in the form of higher rates. The National Petroleum Council has estimated that by 2010 the industry will have to spend annually an additional $1.7 billion to replace and refurbish pipelines. If the additional costs were fully recovered from customers, the average transmission and distribution markup in 2010 is estimated to increase by 17 cents per thousand cubic feet.[28]

Recent Action Plans

Federal policies have been increasingly favorable to natural gas in recent years. During 1993, the Clinton Administration redirected energy policy to encourage the use of natural gas. Three policy initiatives were developed. *The Climate Change Action Plan*, announced in October 1993, declared the Nation's commitment to reducing greenhouse gas emissions. *The Domestic Natural Gas and Oil Initiative* contains explicit measures intended to stimulate markets for natural gas and natural gas-derived products. Finally, *the Natural Gas Strategic Plan,* released in June 1995, addresses issues related to natural gas technology, markets, policy, and the environment.

The Climate Change Action Plan

In 1993, President Clinton and Vice President Gore introduced *The Climate Change Action Plan* as part of a strategy to combat global warming. The plan's key goal is to reduce emissions of greenhouse gases to their 1990 levels by the year 2000. The principal strategies to achieve this goal include the following:

- **Regulatory reform to increase natural gas' share of energy use.** The Administration efforts will include the reform of current pipeline construction rules to reduce unwarranted delays in the construction of new pipeline capacity; the introduction of "performance regulation" rulemaking that would lower prices for pipeline capacity; and a review of the rules regarding the secondary market for pipeline transportation to promote efficient resale transactions. The Department of Energy (DOE) estimates these actions could result in additional gas use of 370 billion cubic feet by the year 2000. Higher natural gas use is expected to reduce greenhouse gas emissions by 2.2 million metric tons of carbon equivalent.

- **Seasonal gas use for control of nitrogen oxides (NO_x).** The Administration will promote the summer use of natural gas in electric utility coal- and oil-fired plants and

[27]The credit was adjusted annually and was originally granted to production from wells drilled before January 1, 1991. The credit was extended as part of the Revenue Reconciliation Act of November 1990.

[28]Energy Information Administration, *Annual Energy Outlook 1995*, DOE/EIA-0383(95)(Washington DC, January 1995), p. 45.

in industrial facilities as an innovative, low-cost NO_x reduction strategy.

- **Commercialization of high-efficiency gas technologies.** DOE would provide funds from 1995 to 1997 for a portion of the cost of demonstrating the effectiveness of high efficiency gas technologies, such as fuel cells. Fuel cells are an environmentally safe method of producing electricity and thermal energy as a byproduct. This technology converts the chemical energy of fuel directly into electrical energy without a combustion process. Funding for this effort has not yet been appropriated.

- **Expansion of the Natural Gas Star program**. The Environmental Protection Agency will expand a public/private partnership program that reduces methane emissions by introducing and promoting cost effective technologies and practices in the natural gas industry. Natural Gas Star was launched in the Spring of 1993 and has 26 partners. The program provides technical assistance, implementation guidelines, and an information sharing network for gas companies to achieve cost effective emissions reductions. The expanded program targets production, transmission, and distribution companies not currently in the program.

The Domestic Natural Gas and Oil Initiative

In December 1993, the Department of Energy (DOE) announced the *Domestic Natural Gas and Oil Initiative*, placing a strong emphasis on replacing oil imports with domestic natural gas. The initiative outlines numerous actions that address issues such as tax policy, advanced drilling technologies, cost of regulation, and market demand. The initiative has two key goals: enhancing the efficiency and competitiveness of U.S. industry, and reducing the trend toward higher energy imports. The Administration intends to accomplish these goals through three major strategic activities and their related actions:

- Increase domestic natural gas and oil production and environmental protection by advancing and disseminating new exploration, production, and refining technologies. DOE is targeting research and development to the needs of small oil and gas producers to help achieve this goal.

- Stimulate markets for natural gas and natural gas-derived products, including their use as substitutes for imported oil where feasible. DOE will work with FERC to remove barriers to environmentally sound construction of additional pipeline and storage facilities. DOE will also encourage increased access to existing facilities while accelerating the development and use of advanced technologies in natural gas storage and distribution.

- Ensure cost-effective environmental protection by streamlining and improving government communication, decisionmaking, and regulation. The primary goal is to simplify regulations without compromising environmental guidelines. An interagency working group composed of representatives from DOE, FERC, the Environmental Protection Agency, and others will be created to improve coordination of regulatory issues affecting gas and oil supplies. The purpose of these efforts is to eliminate duplication in the form of needless paperwork or duplicate permits and hearings.

Natural Gas Strategic Plan

Building on *The Climate Change Action Plan* and *The Domestic Natural Gas and Oil Initiative*, in June 1995, the Department of Energy (DOE) issued the *Natural Gas Strategic Plan*. This plan defines specific goals related to the expanded development and use of natural gas, and defines the role of the U.S. government and industry in partnership to reach these goals. DOE will promote technologies to help U.S. industry meet timetables for air quality goals and ensure adequate supplies for the Nation. The four goals of the plan are to:

- Foster the development of advanced natural gas technologies for use in exploration, production, and consumption applications

- Encourage the use of natural gas in new and existing markets

- Support the removal of policy impediments to natural gas use in new and existing markets

- Foster technologies and policies to maximize the environmental benefits of natural gas use.

The DOE has developed plans to reach the goals that were published in the *Natural Gas Strategic Plan*[29] and intends to accomplish these goals through a series of studies and initiatives.

Conclusion

As the discussion in the chapter highlights, the natural gas industry has undergone a fundamental restructuring over the past two decades. A series of complementary legislative and

[29]U.S. Department of Energy, *National Strategic Plan*, DOE/FE-0338 (Washington, DC, June 1995).

regulatory initiatives has brought the industry to a new level of competition and has provided significant benefits for consumers. Legislative initiatives have provided new opportunities for the expansion of the market for natural gas. The regulatory restructuring has provided the industry with the ability to compete better for these markets against other fuel sources.

The interaction of the extensive regulatory and legislative initiatives since 1988 has resulted in an industry that produced and delivered 3.6 trillion cubic feet more gas in 1994 at prices that are 17 percent lower. However, more significant impacts from some initiatives, including the Clean Air Act Amendments, are likely in the future. This will result as Phase II of the Clean Air Act Amendments are implemented and as the initiatives undertaken as part of the Domestic Gas and Oil Initiative and the Natural Gas Strategic Plan progress.

3. Transportation Flow Patterns

Extensive changes occurred in all areas of the natural gas industry from 1988 through 1994. During this period, U.S. natural gas consumption increased by 15 percent to reach 20.7 trillion cubic feet, the highest level since 1974.[30] By far, the most substantial growth took place in the industrial sector (26 percent), in part because of increases in nonutility generation of electricity (including cogeneration).[31] The commercial and electric utility sectors had much lower increases of 10.2 and 13.3 percent, respectively. The growth in consumption was supported by an increase in U.S. dry gas production of 1.8 trillion cubic feet and a substantial increase in imported gas from Canada. In 1994, imports of natural gas from Canada were 2.6 trillion cubic feet, double the 1988 level. Currently, Canadian imports supply approximately 13 percent of domestic consumption, up from 7 percent in 1988.

The importance of the interstate natural gas transmission network is illustrated by the fact that 27 of the lower 48 States are almost totally dependent upon the system for their natural gas supplies. These supplies must be transported from only 11 States, located primarily in the Southwest and Central Regions (Figure 1). More than 1,200 local distribution companies nationwide distribute these supplies to the ultimate consumer. The major 38 interstate pipeline companies (of more than 100 nationwide) account for more than 76,900 miles of the Nation's 250,000 miles of mainline pipe (21-inch or larger diameter).[32] More than 550 interconnections are within this network, providing customers access to supplies throughout the Nation.

Various elements have influenced gas industry operations and market outcomes since 1988. Federal legislation and regulation are key influences on the industry, especially those related to the basic restructuring of the transportation sector. The introduction of open-access transportation programs brought a whole new orientation to the natural gas pipeline industry.[33] Most throughput on the major interstate pipelines before 1988 was transported from receipt to delivery on the single system of each pipeline company because the gas was owned by the pipeline companies. Today transportation and related services dominate pipeline operations. Approximately 96 percent of all natural gas transported on the interstate system in 1994 represented transportation of gas owned by others, compared with 56 percent in 1986 and only 21 percent in 1981 when interstate pipeline companies were the primary sellers of natural gas. The transformation of the transmission segment of the industry has changed both the objectives and the participants, and altered business relationships within the marketplace (Figure 2).

This chapter discusses the changes that have taken place in natural gas flows from supply areas to markets since 1988,[34] the capability of the interstate network to deliver natural gas, and how the network is being used to accommodate the changing supply and consumption patterns. It highlights some of the differences in consumption and supply patterns since 1988 that may be related to changes in Federal policies. It also discusses the effect of industry restructuring on interstate pipeline flows.

Changes in Flow Patterns

The introduction and extension of market forces dominated the industry and its transmission patterns between 1988 and 1994. Transmission and distribution patterns of natural gas are governed by regional demand conditions, which are constrained by the capacity of the physical network used to move gas to end users. Significant system expansion has occurred since 1988 to accommodate supply and demand changes. Attributes of the expanded physical network have been augmented by the

[30] Unless otherwise specified, gas consumption data are from the Energy Information Administration, *Natural Gas Annual 1993,* DOE/EIA-0131(93) (Washington, DC, November 1993), and *Monthly Energy Review*, DOE/EIA-0035(95/08) (Washington, DC, August 1995).

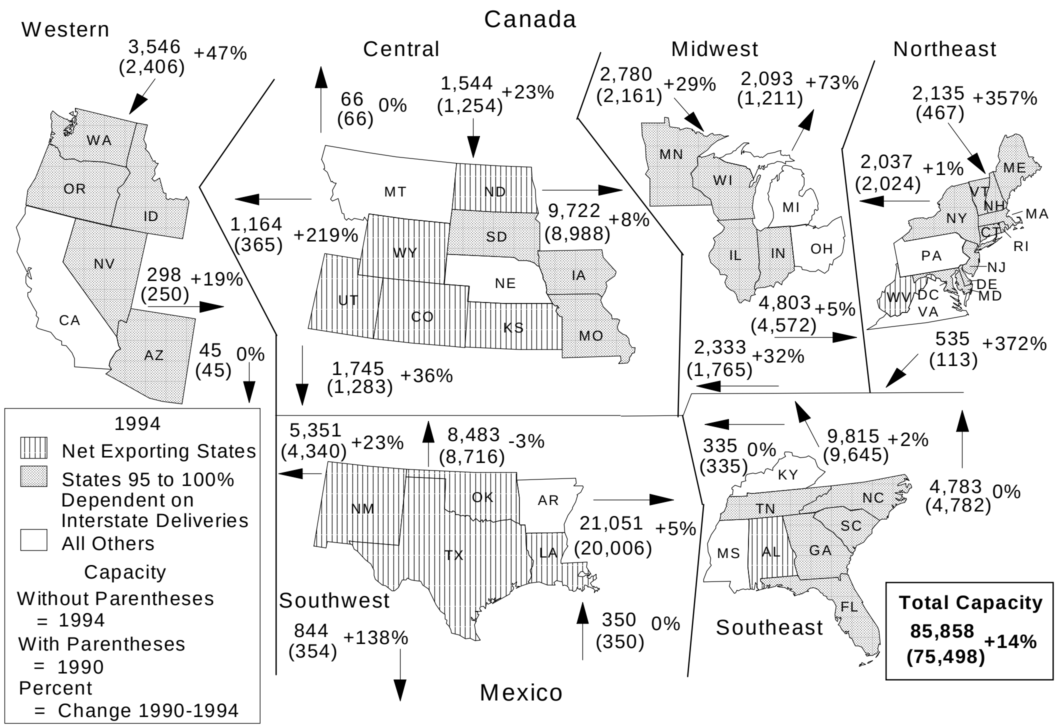
[31] Nonutility generators include all generators that are not included in the assets of electric utilities. These nonutility generators include qualifying cogenerators and small power producers as well as the new independent power producers. Natural gas supplies for nonutility generators are included in industrial gas deliveries.

[32] Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline System Map files.

[33] FERC Order 436 was rendered invalid by the Courts in 1986 and ultimately was replaced by FERC Order 500, which took effect in 1987. Between 1985 and 1987, while litigation proceeded, Order 436 had little practical effect.

[34] The analysis does not always cover the entire period from 1988 to 1994, because of limited data in some areas. Data on interstate pipeline flows are available for the period 1988 through 1993 (and limited 1994). Comprehensive information on the capacity of the pipeline system is only available from 1990, when the Energy Information Administration first compiled statistics on this aspect of the industry. The discussion of capacity changes and changes in utilization rates, therefore, is limited to the 1990 to 1994 period.

Figure 1. Interregional Natural Gas Pipeline Capacity, 1990 and 1994
(Million Cubic Feet per Day)



Note: The interregional capacity total for 1994 has been corrected since the original publication.
Sources: **State Export Status:** Energy Information Administration (EIA), Office of Oil and Gas, derived from: Production and Consumption, *Natural Gas Monthly* (April 1995). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of August 1995.

operational efficiencies resulting from the regulatory restructuring of the interstate pipeline system during this period. These changes to operations have greatly increased the flexibility and accessibility of the system. In addition, lower natural gas prices have increased demand for natural gas.

The principal flow patterns of natural gas from supply areas to markets in the lower 48 States have not changed significantly since 1988. However, several new routes and major increases on several existing routes developed during the period (Figure 3). These changes reflect the effort to meet regional market demands with (often distant) available supplies.[35] The major distribution patterns for natural gas remain those from the Southwest Region to markets located in the Midwest and Northeast Regions. This gas originates primarily in Texas and Louisiana and flows through the Southeast and Central Regions to those markets. Significant gas supplies also flow from the Southwest to markets in the Western Region (primarily California). Although several major pipelines were completed in the 1970's and 1980's to import more Canadian gas to the United States, flows from Canada accounted for only 7 percent of total national consumption in 1988.

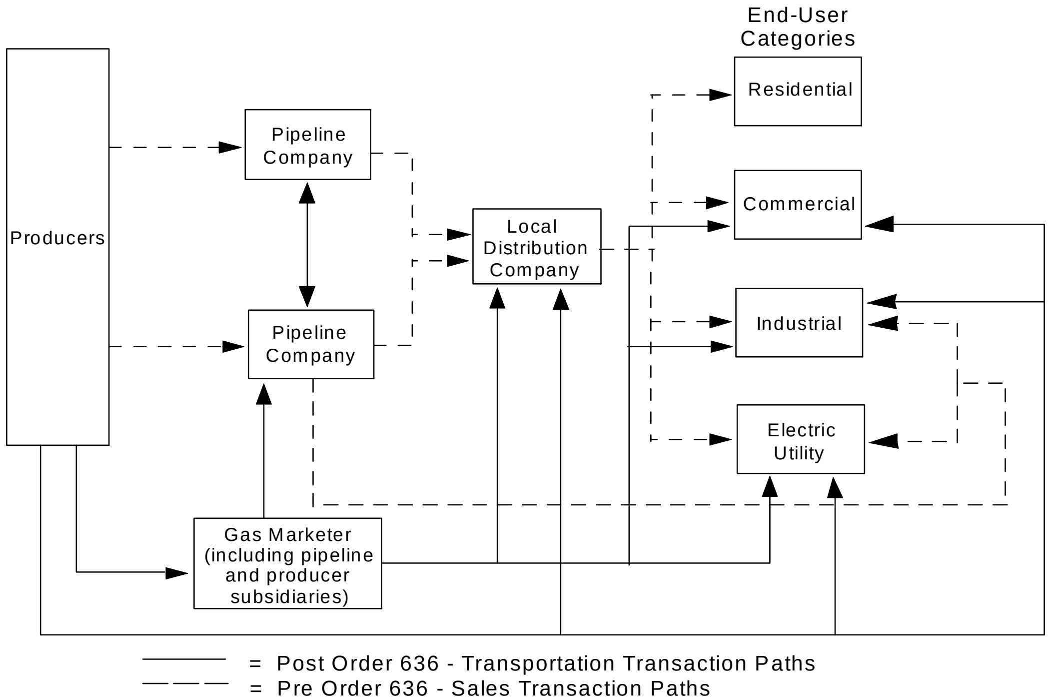
The major change in natural gas flow patterns since 1988 relates to the rapid rise in U.S. imports of Canadian natural gas (Figure 3). For instance, from 1988 through 1994:

- Imports of Canadian gas into the Western Region increased by 51 percent (Figure 4) as more supplies became available from western Canada. Lower prices for Canadian natural gas supplies, the growing demand for gas in the Western Region, and passage of stricter environmental restrictions helped spur this growth.

- Imports of Canadian gas into the U.S. Northeast rose from only 79 billion cubic feet in 1988 to 555 billion cubic feet in 1994. Growth in industrial demand, including electricity generation from both utility and nonutility generators, and in residential demand brought on this change.

[35] For instance, one of the earliest regions producing natural gas for market was the Northeast Region. As some of its fields in Appalachia became depleted in the 1940's, long-haul transmission lines began to be installed to tap into distant developing supply areas.

Figure 2. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing



Note: Post Order 636, local distribution companies still provide sales service to residential and most commercial gas consumers.
Source: Energy Information Administration, Office of Oil and Gas.

- Canadian gas also became more important in the Midwest Region; imports increased by 57 percent, but natural gas consumption in the region increased by only 8 percent during the period.

Another major change in natural gas flow patterns has been the increase in flows from the Southwest and Central Regions to the Western Region. These changes occurred as new supplies were developed in the Rocky Mountain area of Colorado/Wyoming and the coalbed methane fields of southern Colorado and northern New Mexico. Much of this production development occurred in tight gas formations and coalbeds. Production from these sources was stimulated by the Section 29 production tax credits. Volumes destined for the Western Region from the Central Region increased by 915 percent, from 33 billion cubic feet in 1988 to 335 billion cubic feet in 1994. About half of these supplies flowed to the enhanced oil recovery markets in California.

Additional variability in flow patterns has originated in natural gas trade with Mexico. Exports of U.S. natural gas to Mexico grew rapidly between 1988 and 1992, increasing from 2 billion cubic feet in 1988 to 96 billion cubic feet in 1992. But since 1992, the level of exports has fallen by half. During the early 1990's, Mexico was viewed as a large potential market for some of the additional natural gas supplies developing in the Southwest Region. Several additional export terminals were opened in 1991; these more than doubled existing crossborder capacity. Crossborder capacity will expand further with the completion of current projects designed to move gas to Mexican consumers. While several border points with Mexico provide reverse flow capability, imports of Mexican gas to the United States remain negligible.

Changes in Consumption Patterns

Changes in the demand for natural gas are the basic forces that motivate decisions in the production, import, transportation, and distribution of natural gas. Consumers of natural gas respond both to economic signals, such as increased economic activity and relative prices, and to other external influences when they make energy choices. Federal legislation and policies affect the economic environment and other external factors that influence the trends and patterns in consumer energy choices. However, consumers' current decisions about energy are seldom totally independent of their earlier decisions. Because most energy choices are conditioned on matching fuel to available energy-

Figure 3. Flow Patterns on the Interstate Pipeline Network, 1994

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

using equipment, changes in consumption patterns take place gradually as consumers purchase new equipment to expand or replace existing energy-using facilities. Thus, trends in natural gas consumption generally reflect legislative and policy initiatives over the longer term.

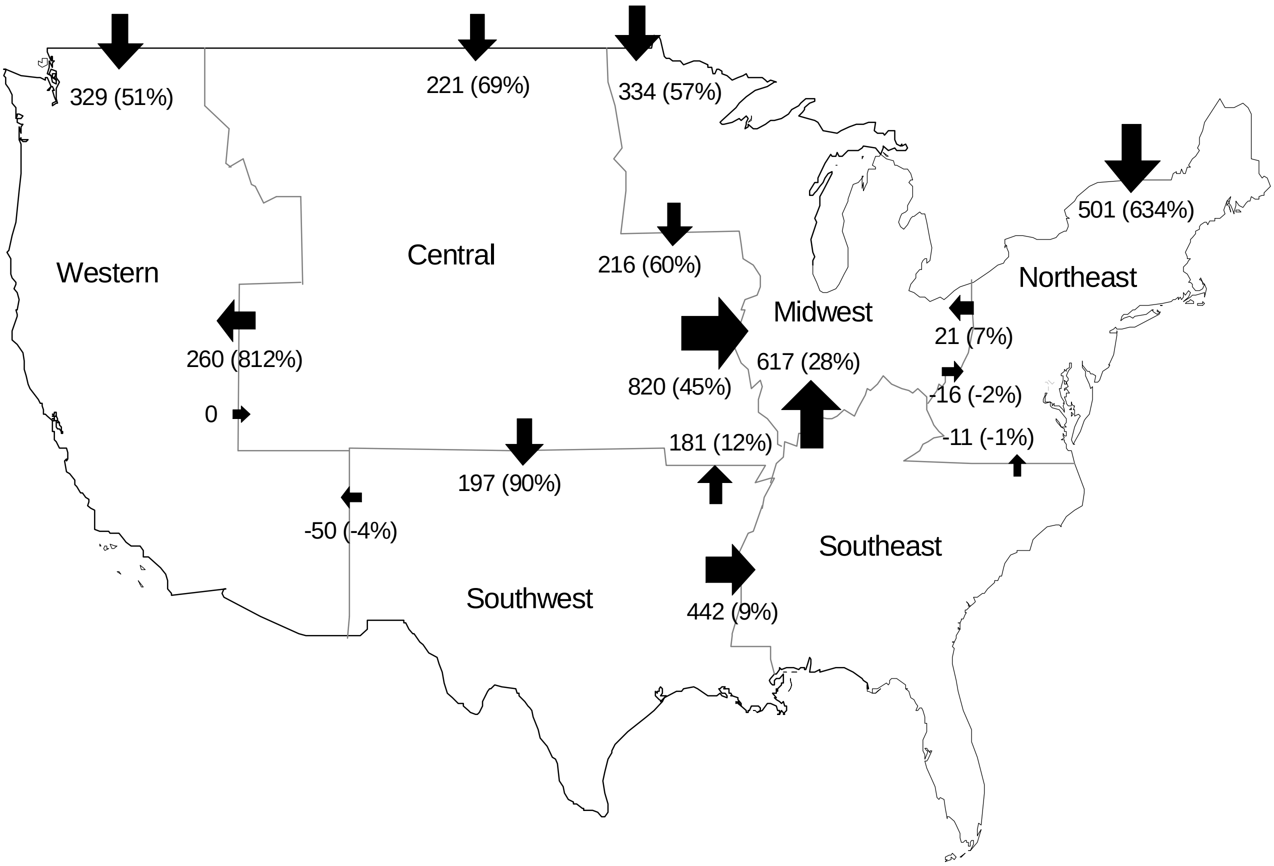
Total national natural gas consumption increased at an annual rate of 2.4 percent to the level of 20.3 trillion cubic feet between 1988 and 1993.[36] Gas consumption as a share of total domestic energy consumption rose correspondingly from 23.1 percent to 24.8 percent. During this same period, deliveries to end-use customers grew at an annual rate of 2.5 percent (Table 3).[37]

Natural gas consumption trends vary by sector and region. The use of natural gas for heating and its resulting seasonal pattern continues to dominate residential and commercial applications. Gas use in the industrial and electric utility sectors is increasingly related because the gas consumed by nonutility generators for the production of electricity is treated as part of industrial consumption. This section discusses trends in national and regional gas consumption. The discussion of sectoral consumption at a national level identifies differences in the

[36]Currently, final consumption data on both a regional and sectoral basis are available only through 1993, although consumption data by customer sector are available for 1994.

[37]Nationally, deliveries to end-use consumers grew slightly faster than total consumption because natural gas consumed in production and delivery of gas (lease and plant fuel and pipeline use) grew at an annual rate of only 1.1 percent.

Figure 4. Interregional Changes in Flow Levels on the Interstate Pipeline Network Between 1988 and 1994
(Volumes in Billion Cubic Feet)



Source: Energy Information Administration, *Natural Gas Annual 1988* (October 1989) and "Natural Gas Annual 1994," draft report.

relevant demand influences, while the description of regional consumption reflects the differences in regional components and the amount of demand by sector.

End-Use Consumption

From 1988 through 1993, total end-use consumption in the lower 48 States grew from 16.2 to 18.4 trillion cubic feet (Table 4), an average annual rate of 2.5 percent. The residential and commercial sectors had growth rates of only 1.4 and 1.8 percent, respectively (Table 3). Slow growth in natural gas consumption in the residential and commercial sectors reflects, at least in part, price changes of energy sources and advances in energy conservation, especially improvements that reduce the amount of energy used to heat a given amount of building space. Despite substantial increases in gas heating applications during the 1988 to 1993 period, the growth in residential and commercial sector gas consumption barely exceeded the overall increase in the population. Growing gas use for space and water heating has been partially offset by improved insulation and new gas heating technologies. A number of new Federal and State laws and policies, including programs to aid low-income home owners retrofit energy conservation measures, have encouraged end-use conservation. These initiatives, including the Energy Policy Act as discussed in Chapter 2, have been quite successful in improved energy end-use efficiency, thus slowing the increase in the growth of demand for gas, especially in the residential and commercial sectors.

Industrial consumption, which represented about 40 percent of all end-use gas consumption in 1993, rose at an annual rate of 4.5 percent. Natural gas consumed by nonutility generators (NUG's) is included in industrial sector gas consumption, so some of the increased consumption can be attributed to the development of nonutility generators of electricity. Much of the

Table 3. Growth in Natural Gas Consumption and Related Factors by Region Between 1988 and 1993

Region	Percent Population Growth	Population Weighted Average Heating Degree Days[1]	Annual Percent Growth of Gas Consumption				
			Residential	Commercial	Industrial	Electric Utility	Total
Northeast	2.4	4,484	1.1	3.6	9.0	4.0	4.0
Southeast	7.5	2,099	2.0	1.3	4.1	3.1	3.0
Midwest	3.3	5,162	1.1	0.7	4.1	8.7	2.1
Central	4.2	4,959	2.2	0.9	5.9	3.5	3.1
Southwest	5.9	2,055	1.5	2.4	2.7	0.1	1.8
Western	10.8	2,425	1.3	1.0	7.3	-2.2	2.3
Total Lower 48 States	5.5	--	1.4	1.8	4.5	0.4	2.5

[1]Degree-days are relative measures of outdoor air temperature used as an index for heating requirements. Heating degree-days are the number of degrees per day that the daily average temperature is below 65 degrees Fahrenheit. The daily average temperature is the mean of the maximum and minimum temperatures in a 24-hour period. The values shown are calculated by weighting State values for heating seasons 1988-89 through 1993-94 by population and averaging the values over the period. A heating season is from November of one year through March of the next year.

Sources: **Population:** U.S. Department of Commerce, Bureau of Census, *Statistical Abstract of the United States, 1994* (September 1994). **Heating Degree Days:** U.S. Department of Commerce, National Oceanic and Atmospheric Administration, *State, Regional, and National Monthly and Seasonal Heating Degree Days* (July 1993) and subsequent monthly updates. **Population Weighted Average Heating Degree Days:** Energy Information Administration, Office of Oil and Gas, derived from: Population and Heating Degree Days. **Gas Consumption:** 1988—Energy Information Administration, *Natural Gas Annual 1992*, Vol. 1 (November 1993); 1993—Energy Information Administration, *Natural Gas Annual 1993* (October 1994).

Table 4. Natural Gas Deliveries to End-Use Consumers by Region and Sector, 1988 and 1993
(Billion Cubic Feet)

Region	Residential		Commercial		Industrial		Electric Utility		Total	
	1988	1993	1988	1993	1988	1993	1988	1993	1988	1993
Northeast	1,177.2	1,244.4	619.1	740.6	629.8	968.5	232.9	283.1	2,659.3	3,236.9
Southeast	369.7	407.4	269.0	286.9	766.9	938.2	196.1	228.5	1,601.6	1,860.8
Midwest	1,546.1	1,636.7	760.6	789.2	1,158.7	1,413.5	33.1	50.3	3,498.5	3,889.8
Central	507.9	564.9	334.6	350.5	397.7	530.5	37.5	44.5	1,277.6	1,490.2
Southwest	412.3	444.1	309.2	348.3	2,737.1	3,127.6	1,514.6	1,519.0	4,973.3	5,439.4
Western	604.1	645.5	355.0	373.8	625.3	887.6	590.7	528.9	2,174.9	2,436.2
Total Lower 48 States	4,617.3	4,943.0	2,647.5	2,889.3	6,315.5	7,866.9	2,604.9	2,654.3	16,185.2	18,353.5

Sources: Energy Information Administration. **1988:** *Natural Gas Annual 1992*, Vol. 1 (November 1993). **1993:** *Natural Gas Annual 1993* (October 1994).

expansion in NUG's can be attributed to the success of Title 2 of the Public Utility Regulatory Policies Act of 1978, which established a program to encourage cogeneration and renewable resource electricity generation. The electricity producers who responded to this 1978 initiative form the backbone of the new nonutility power industry. Many of the NUG's are part of industrial plants that use cogeneration to produce both electricity and useful thermal energy. Therefore, gas consumption in industrial facilities that include NUG's cannot be separated between electricity and other industrial uses. Industrial establishments with NUG facilities are estimated to account for more than 20 percent of all industrial gas deliveries in 1993.[38]

Natural gas consumption in the electric utility sector was nearly stagnant, growing at an annual rate of only 0.4 percent. The low growth in electric utility consumption reflects the marginal role of utility gas-fired generation. Many utilities use gas as a swing fuel to fill in for shortfalls of nuclear generation or hydroelectric resources. Thus, gas consumption by these utilities varies according to the availability of generation from these lower variable cost resources. For example, gas consumption by electric utilities increased by more than 11 percent (about 300 billion cubic feet) between 1993 and 1994, partly because a drought reduced hydroelectric generation.

The use of natural gas for vehicle fuel comprises a large potential market, but it is still in its infancy. Legislative initiatives, including provisions in the Energy Policy Act and the Clean Air Act Amendments, to encourage alternatives to gasoline-powered vehicles have induced significant research and development of natural gas-powered vehicles.[39] But their total impact on natural gas consumption is barely measurable on a national scale. Natural gas used as a vehicle fuel represents a very small fraction of total consumption. The amount of natural gas delivered for use as vehicle fuel in 1993 was only 1 billion cubic feet, compared with U.S. deliveries of 18.5 trillion cubic feet to all consuming sectors. However, the rapid growth of vehicle-fuel gas consumption indicates the potential for natural gas in this developing market.

Regional End-Use Consumption

There are striking differences in gas consumption among geographic regions. Patterns of gas consumption vary in response to regional differences in gas penetration rates and to changes in the level of economic activity, as well as other, more transitory effects. Significant quantities of natural gas are used for space heating in the winter and electric generation in the summer in some regions. This temperature-sensitive gas consumption can drive fluctuations in regional consumption from year to year if there are major variations in weather patterns.

Three of the six regions—the Southwest, the Midwest and the Northeast—account for nearly 70 percent of all gas consumption. The Southwest alone consumes nearly 30 percent of all gas used in the lower 48 States. In the Southwest, gas consumption is concentrated in the industrial and electric utility sectors (85 percent of the total) (Figure 5). In this region, a significantly smaller share of gas use (less than 15 percent) is devoted to residential and commercial customers than is the case elsewhere. In the other two major gas-using regions, the Midwest and the Northeast, a much larger share of gas consumption (60 percent or more) is in the residential and commercial sectors.

Industrial gas consumption in the Southwest continues to represent the largest single regional use of gas, even though the region's share of industrial consumption fell from 43 percent in 1988 to 40 percent in 1993. The Southwest continues to attract industries, such as chemical manufacturing, that use large quantities of gas. In addition, the Southwest has been the leading region in NUG development; by 1993 the Southwest had about 32 percent of the national NUG generating capacity. Industrial consumption in other regions, noticeably the Western, Northeast, and, although from a small base, the Central Region, has shown significant growth. NUG development has contributed to this growth in industrial consumption in both the Western and Northeast Regions.

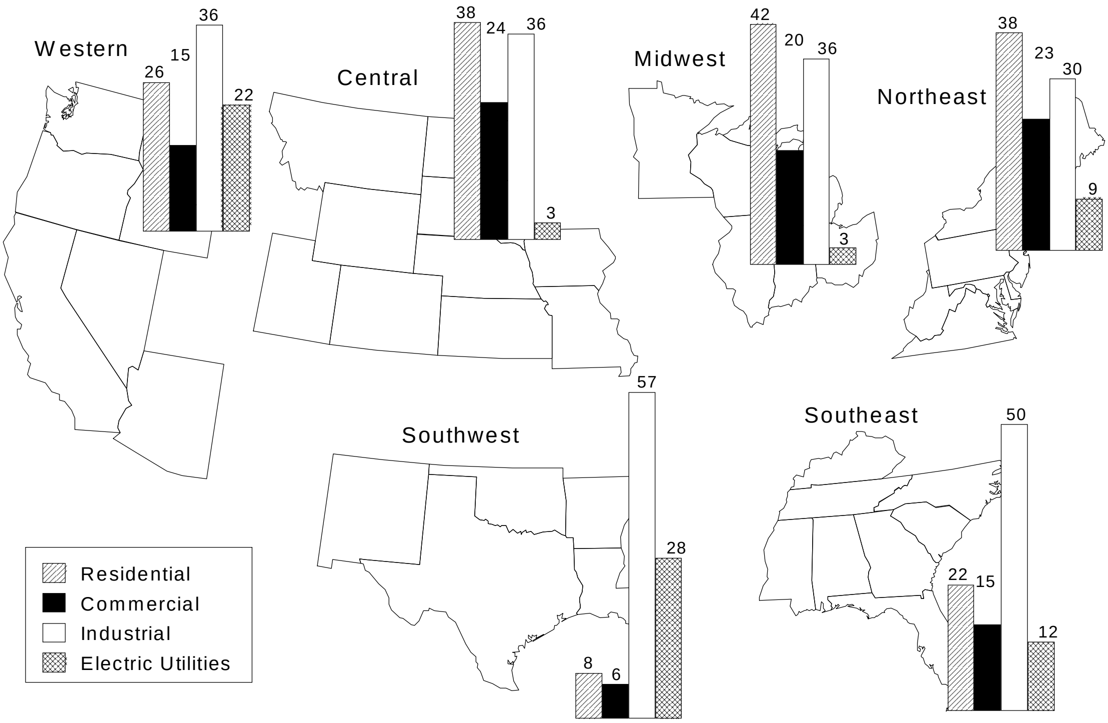
Electric utilities consume the least amount of natural gas of the end-use sectors in each region except the Southwest and Western. In 1993, utilities in the Southwest used 57 percent of all the gas supplied to electric utilities; another 20 percent was used by electric utilities in the Western Region. Although a few utilities in Florida, New York, and other States outside of these two regions also use gas regularly, their effect on gas consumption is relatively small.

As discussed in Chapter 2, patterns of increased gas consumption in large industrial and utility boilers were disrupted by the Power Plant and Industrial Fuels Use Act of 1978 (FUA).

[38]The proportion of industrial gas deliveries going to establishments with nonutility generation facilities is based on data from Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

[39]In order to promote the availability of vehicular natural gas (VNG), the Federal Energy Regulatory Commission issued Order 543 on July 16, 1992, simplifying the certification process for VNG retail sales and minimizing the reporting requirements of VNG wholesalers.

Figure 5. Percent of End-Use Natural Gas Consumption by Sector Within Regions, 1993



Note: Totals may not equal 100 because of independent rounding.
Source: Energy Information Administration, *Natural Gas Annual 1993*.

FUA discouraged both utility and industrial gas-using capacity expansion. However, FUA probably helped start the surge in nonutility generation because it permitted exemptions from FUA for industrial cogenerators. On the other hand, electric utilities started to build new coal-fired and nuclear power plants during the period of FUA restrictions because they were not allowed to rely on additional gas resources. By the time FUA was modified in 1987, most utility expansion needs could be filled by these new plants and by capacity that had been built by NUG's. Therefore, electric utility consumption of gas did not grow compared to the historically high levels of consumption in earlier periods. Nor does it appear that the pollution abatement requirements of the Clean Air Act Amendments have encouraged utilities to substitute significant amounts of gas for other fuels thus far.

Moreover, the expansion of NUG's in the industrial sector makes it difficult to separate growth in industrial applications of natural gas from growth in industrial site generation. Industrial gas consumption, cushioned by NUG development and encouraged by attractive gas prices and new access to pipeline transportation, has nearly returned to levels achieved in the early 1970's. The growth of industrial gas consumption is especially impressive in regions such as the Northeast where pipeline expansions and Canadian import availability have produced annual consumption growth rates as high as 9.0 percent between 1988 and 1993 (Table 3).

Despite the electric utilities' small share in gas consumption, much interest has been focused on gas used for electricity production for two reasons. First, although utility gas consumption has been growing, it still has not returned to its historical peak levels before FUA in the early 1970's. In 1993, electricutility gas deliveries were 33 percent below the 1972 peak.

Second, rapid expansion of nonutility, gas-fired generation led many forecasters to predict that NUG demand for gas would grow substantially during the remainder of the century and would compensate for the slow recovery of utility gas consumption. However, a restructuring of the electric industry has begun in response to provisions of the Energy Policy Act of 1992. Because the restructuring process is still in an early phase, there is a great deal of uncertainty about the need for additional electric generation in a restructured industry. This uncertainty may postpone additions to gas-fired generating capacity by both electric utilities and NUG's.

Changes in Supply Patterns

Supply patterns from domestic and foreign sources have changed considerably since 1988. Changes at the natural gas supply source frequently require flow adjustments downstream. A review of the regional changes since 1988 reveal certain outcomes that are attributable to Federal actions by their direct impact on the extraction process or by affecting production decisionmaking.

Changes in Federal regulations, policies, and directives have both promoted and imposed restrictions on natural gas production or production-related activities. Production was advanced by numerous Federal actions including FERC Order 636, which increased competition among producers and drove down the price. The combined effect of lower prices and more secure service has promoted expanded gas sales and thus production in the United States.[40] To supply the expanding market, producers in the United States increased production of dry natural gas by 1.8 trillion cubic feet between 1988 and 1994, from 17.1 to 18.9 trillion cubic feet.

Other elements that stimulate natural gas supply include U.S. tax provisions, which have been modified over the years. Adjustments to existing law and inclusion of new provisions inevitably affect the expected profitability of oil and gas investments by altering the net returns or perceived risk. The net effects of tax changes that are not energy specific (e.g., changes to depreciation rules or marginal income tax rates) change over time, but for simplicity most of them are assumed to have a uniform impact across all regions. Energy specific tax provisions, such as the production tax credits for gas from coalbeds or tight formations, have a more direct impact and affect regional activity.

The interest in gas trade between the United States, Canada, and Mexico is reflected in the U.S.-Canada Free Trade Agreement (CFTA) and the North American Free Trade Agreement (NAFTA). U.S. trade with Canada more than doubled between 1988 and 1994, which indicates the stimulatory impact of the CFTA. The acceptance of NAFTA did not substantially alter U.S. trade with Mexico; however, it did formalize the process.

Environmental concerns have stimulated gas markets but have also imposed some constraints. Drilling is restricted in several areas along the Outer Continental Shelf. Currently an estimated 9.4 trillion cubic feet of the resource base in the Offshore is off-limits to drilling (see Chapter 2).

Regional Supply Patterns

Only the Southwest and Central Regions of the United States are net producing regions. The other four regions—Midwest, Northeast, Southeast, and Western—rely predominantly on supplies from the Southwest, Central States, and Canada to meet regional demand.

The Southwest Region, onshore and offshore, accounts for most of the gas produced in the lower 48 States (Figure 6). Production in the region during 1994 totaled 14.8 trillion cubic feet—79 percent of lower 48 production and 6.1 percent higher than in 1988. The Southwest Region includes the three largest producing States: Texas, Louisiana, and Oklahoma. Texas is the largest producing State, producing 6 trillion cubic feet of dry gas in 1994 from huge natural gas fields along the Texas Gulf Coast, in the Panhandle Region, and the Permian Basin (which extends into New Mexico). Louisiana possesses some of the oldest producing gas fields, including the large Monroe field in the northern region of the State (discovered in 1916). While production has grown in recent years, Federal action had a more discernible direct impact on the offshore areas than the onshore.

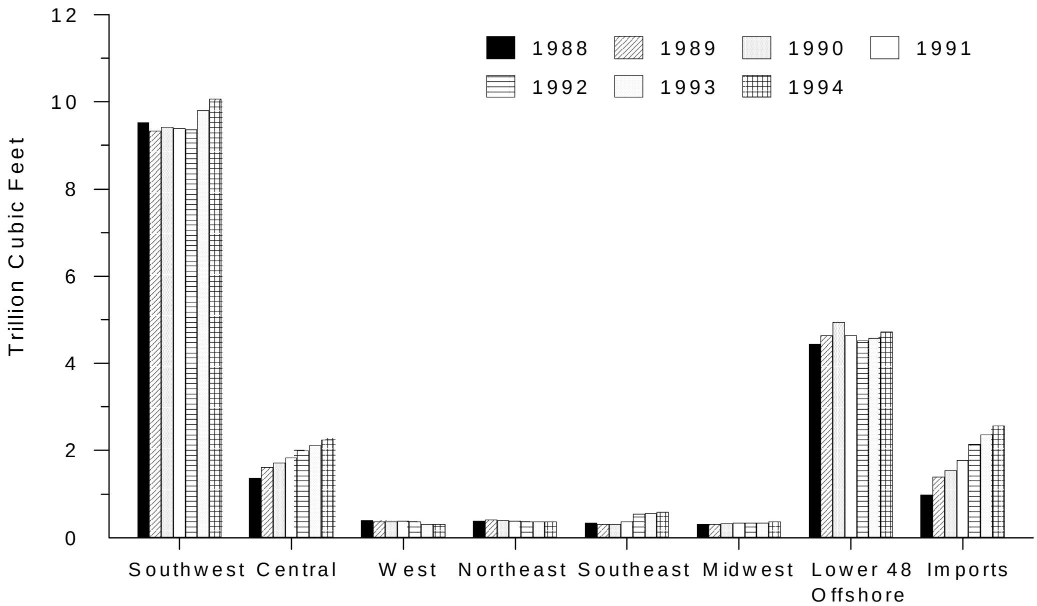
Production from Federal offshore waters, 99 percent from the Gulf of Mexico, increased 7 percent from 1988 to 1994 despite an overall decline in offshore reserves from 32 to 27 trillion cubic feet.[41] Widespread moratoria on offshore supply activities were implemented in 1990 by a combination of Presidential and Congressional decisions. These actions preclude supply activities in most of the Federal offshore regions of the lower 48 States. The offshore moratoria and the tougher emissions standards of the Clean Air Act Amendments clearly have not prevented development of and production from currently known fields to this point; however, the constraint on expansion likely contributes to the decline in reserves.

The Central Region is the other net producing region of natural gas. Production from the Central Region grew 59 percent between 1988 and 1994, from 1.4 to 2.2 trillion cubic feet. The region extends over a vast area and contains numerous producing areas. The producing areas of the various States within the Central Region have responded differently to Federal policy provisions. Wyoming made large increases in production in the late 1980's, boosting its 1988 production by over 50 percent to reach 780 billion cubic feet in 1994. Deep gas and new production from the Overthrust Belt were large contributors to this increase, which may be attributed more to advances in technology than to Federal policy. Much of the Kansas production of 671 billion cubic feet comes from the giant Hugoton gas field, which despite its age still produces the largest gas volume of any single U.S. gas field. Colorado is

[40]Regional marketed dry gas production for 1994 was estimated based on the Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(95/04), (Washington, DC, April 1995).

[41]Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216, 1988-1994 Annual Reports (Washington, DC).

Figure 6. Dry Natural Gas Production by Region and Imports, 1988-1994



Sources: Energy Information Administration: **Onshore:** 1988—*Natural Gas Annual 1991* (October 1992). 1989-1993—*Natural Gas Annual 1993* (October 1994). 1994—*Natural Gas Monthly* (April 1995). **Offshore:** *U.S. Crude Oil*, *Natural Gas*, and *Natural Gas Liquids Reserves* (various issues, 1989-1995).

another important producing State in this region, producing 447 billion cubic feet in 1994. Most of the growth in production came from the San Juan Basin. New gas from the San Juan Basin is predominantly coalbed methane, and its phenomenal growth is attributed to the Federal tax credits available on coalbed methane production from wells drilled before January 1, 1993.

The remaining regions in the lower 48 States together accounted for only 8.6 percent of 1994 production, a slight increase from the 8.3-percent share in 1988. Although the aggregate figures are relatively modest, some of the data for individual States indicate the impact of some Federal policy provisions.

- Michigan, by far the largest producing State in the Midwest Region during 1994, increased natural gas production by 19 percent between 1988 and 1994. Some of this growth was enhanced by the unconventional gas tax credit, which benefited production from the Antrim Shale tight formation.

- The Southeast Region increased its share of total lower 48 dry gas production from 2 percent in 1988 to 3 percent in 1994, responding to the tax credit on coalbed production, which resulted in increased marketed production from the Black Warrior basin of Alabama.

Natural gas imports are an important adjunct to U.S. supplies. U.S. imports of Canadian gas have more than doubled since the signing of the U.S.-Canada Free Trade Agreement, reaching 2.6 trillion cubic feet in 1994. The extensive import and export trade reflects the trend toward development of an increasingly integrated North American gas industry. Canada's large resource base and relatively low-cost gas supplies provide U.S. marketers and consumers with increased supply options. The increased competition confronting domestic gas producers has been significant in keeping gas prices low, despite evidence that some domestic producers are coming close to their productive capacity. Most imported gas enters the West (more than 825 billion cubic feet in 1993), a little over a third of all imports. This is followed by the Northeast, Central, and Midwest Regions with 24, 22, and 18 percent of imports, respectively.

U.S. imports of natural gas are offset slightly by exports to Canada and Mexico from the lower 48 States (100 billion cubic feet of gas were exported to Canada and Mexico in 1994, up from only 22 billion cubic feet in 1988). The 1994 exports to both Canada and Mexico are down from the peak year of 1992 when the volume to those neighboring countries totaled 164 billion cubic feet.[42]

[42]Federal policy generally has not affected liquefied natural gas (LNG) imports. The LNG facility at Lake Charles, LA, was reopened on an open-access basis by FERC directive. However, the dominant factor affecting operations at this facility and that in Everett, MA, has been the relatively low prices of alternative supplies. Even with higher prices, which are not expected in the near term by most analysts, these facilities are unlikely to be affected by Federal policy actions to date.

Transmission Network

The recent changes in the industry have increased reliance on the transmission network and have improved operational efficiency. The open-access and capacity release programs and availability of market hubs for physical transfers of gas have tended to create more gas movements among multiple pipelines. In today's natural gas marketplace the customer has had to assume greater responsibility for transportation arrangements and naturally has sought the least cost and most efficient means of delivery. As a result, the volume of gas moving among several pipeline systems on the way to market has grown. A rough measure of this change is a comparison of the relative magnitude of total reported interstate gas pipeline throughput with total domestic gas consumption.[43] Prior to 1988 (when most of the volumes transported on the major interstate pipelines was still owned by the pipelines), the ratio of reported interstate throughput to total consumption was 1.25:1; in 1994, it grew to 1.42:1. In other words, for each unit of gas consumed in 1994, 1.42 units of gas were moved on the interstate network. The growth in this measure is a subtle indicator of the increasing integration of the interstate network and the increasing competitiveness among pipeline companies.

Regional Use of Transportation Capacity

The availability of natural gas pipeline capacity, as well as its use, varies throughout the country. Each region has its own natural gas service profile (see Appendix B). Increased use of capacity is encouraged in today's market under FERC Order 636. Sellers and buyers have greater access to and use of pipeline capacity, resulting in the use of multiple routes to move supplies from producers to consumers. Annual throughput for the major interstate pipeline companies rose by 25 percent during the period.[44] When compared with 1990[45], average pipeline utilization rates in 1994 increased for 15 of the 23 interregional flow combinations, whereas 6 decreased (Table 5).

Several interregional flows remain relatively low compared with available capacity. For instance, pipelines entering the Midwest, particularly from the Southeast Region, still show a relatively low average annual utilization rate, 68 percent (although up from 64 percent in 1990 (Table 5)). Absent downstream and upstream bottlenecks, capacity exists to increase volumes into the Midwest, for instance, by an average of about 7 billion cubic feet per day. The average-day utilization of capacity at other regional boundaries varied from a low of 56 percent, occurring both from the Southwest to the Central Region and from the Northeast to the Midwest, to a high of 95 percent from Canada to the Central Region.[46] However, the overall average utilization rate decreased by 1 percentage point between 1990 and 1994.

The Southwest Region, which is the Nation's principal producing region, has the capability to export as much as 35.7 billion cubic feet per day to other regions of the United States (Figure 2). That capacity was used in 1994 at an average rate of only about 63 percent, down from its 1990 level of 68 percent. This drop mainly stemmed from capacity additions that came on line to serve the Western Region, particularly California.

At the individual pipeline company level, capacity utilization has increased significantly during the past 4 years. Of the 36 pipeline companies for which data were available, 22 showed an increase in usage on a system-wide basis in 1994 when compared with 1990.[47] Four pipeline systems serving the Western Region experienced a decrease, reflecting the availability of additional pipeline capacity without a corresponding increase in demand. Surprisingly, usage levels also decreased in the Northeast Region for half of the systems

[43]Total sales and transported (for others) volumes reported by the major interstate pipeline companies on FERC Form 11, "Natural Gas Pipeline Company Monthly Statement," 1988 and 1994. If all gas supplies were transported from wellhead to ultimate consumer on a single interstate pipeline, this ratio would be 1:1. In fact, however, the ratio is always higher since in some cases, it is physically impossible to move gas supply to market area without routing gas over more than one interstate pipeline system. This results in some double counting of transported volumes.

[44]Less Kern River and Iroquois pipeline companies that did not exist in 1990, and seven trunk pipelines whose throughput volumes duplicate figures reported for the others.

[45]Data are available only from 1990 through 1994. See Energy Information Administration, *Capacity and Service on the Interstate Natural Gas Pipeline System, 1990*, DOE/EIA-0556 (Washington, DC, June 1992).

[46]Movements of gas to and from Mexico were excluded in identifying low and high capacity utilization rates, because of the relatively small volumes.

[47]The capacity utilization rates discussed in this paragraph are based upon the volumes of gas carried on an entire pipeline system relative to a calculated capacity level. It is an alternative method of measuring, comparing, and evaluating the reasonableness of changes in usage rates. For 1990, the rates were based upon monthly throughput volumes (transportation plus sales) reported per pipeline divided by the largest monthly throughput reported during the period 1978 through 1990; for 1994, 1978 through 1994. The largest reported monthly volume was used as an approximation of a 100-percent load factor or a surrogate for full capacity utilization. Each pipeline system was given a region-to-region designation based on its supply-to-market flow pattern and the region in which deliveries as a percent of total system deliveries were the highest. Data from the Federal Energy Regulatory Commission, Form FERC-11, "Natural Gas Pipeline Monthly Statement," and the Energy Information Administration, Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," were used to derive the usage rates and assignment of regions.

Table 5. Interregional Pipeline Capacity, Average Daily Flows, and Usage Rates, 1990 and 1994

Receiving Region	Sending Region	Capacity (MMcf per day)			Average Flow (MMcf per day)			Usage Rate (percent)		
		1994	1990	Percent Change	1994	1990	Percent Change	1994	1990	Change
Canada	Central	66	66	0	9	44	-80	14	67	-53
	Midwest	2,093	1,211	73	1,443	961	50	69	79	-10
Total into Region		2,159	1,277	69	1,452	1,005	44	67	79	-12
Mexico	Southwest	844	354	138	117	38	208	14	11	3
	Western	45	45	0	7	5	40	16	11	5
Total into Region		889	399	123	124	43	188	14	11	3
Central	Canada	1,544	1,254	23	1,469	941	56	95	75	20
	Midwest	2,333	1,765	32	1,489	974	53	[a]90	[a]75	15
	Southwest	8,483	8,716	-3	4,722	4,119	15	56	[a]49	9
	Western	298	250	19	0	196	-100	0	78	NA
Total into Region		12,658	11,985	6	7,680	6,230	23	[a]67	[a]56	11
Midwest	Canada	2,780	2,161	29	2,487	1,733	44	89	[a]84	5
	Central	9,722	8,988	8	6,986	5,684	23	72	63	9
	Northeast	2,037	2,024	1	887	714	24	[a]56	[a]45	11
	Southeast	9,815	9,645	2	6,712	6,134	9	68	64	4
Total into Region		24,354	22,818	7	17,072	14,265	20	[a]71	[a]64	7
Northeast	Canada	2,135	467	357	1,656	309	436	78	66	12
	Midwest	4,803	4,572	5	3,185	3,464	-8	66	76	-10
	Southeast	4,783	4,782	0	3,705	4,086	-9	77	85	-8
Total into Region		11,721	9,821	19	8,546	7,859	9	73	80	-7
Southeast	Northeast	535	113	373	86	69	25	[a]75	[a]69	6
	Southwest	21,051	20,006	5	14,374	14,703	-2	68	73	-5
Total into Region		21,586	20,119	7	14,460	14,772	-2	[a]68	73	-5
Southwest	Central	1,745	1,283	36	1,122	572	96	[a]79	[a]58	21
	Mexico	350	350	0	19	0	NA	5	0	NA
	Southeast	335	335	0	15	15	0	[a]60	[a]60	0
Total into Region		2,430	1,968	23	1,156	587	97	[a]64	[a]69	-5
Western	Canada	3,546	2,406	47	2,866	1,871	53	81	78	3
	Central	1,164	365	219	917	196	368	79	54	25
	Southwest	5,351	4,340	23	3,383	3,910	-13	63	90	-27
Total into Region		10,061	7,111	41	7,166	5,977	20	71	84	-13
Total Lower 48 States		**85,858**	**75,498**	**14**	**57,656**	**50,738**	**14**	**[a]69**	**[a]70**	**-1**

[a]Usage Rate shown may not equal the average daily flows divided by capacity because in some cases no throughput volumes were reported for known border crossings. This capacity was not included in the computation of usage rate.

MMcf = Million cubic feet. NA = Not applicable.

Sources: Energy Information Administration (EIA). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database as of August 1995. **Average Flow:** "Natural Gas Annual 1994," draft report. **Usage Rate:** Office of Oil and Gas, derived from Pipeline Capacity and Average Flow.

serving that market (which may be attributable to a relatively mild winter). Nevertheless, on average, system-wide capacity utilization levels increased in each of the consuming regions, except the Western (down 10 percent). The Northeast showed an overall increase of about 5 percent; the Southeast 12 percent; and the Midwest 4 percent. The level of pipeline capacity has grown between the United States and Canada, and the utilization of that capacity has remained high. Use of Canadian import capacity in 1994 (77 percent) was about the same as in 1990 (78 percent).

The existing level of interregional capacity, when combined with available underground storage inventories and deliverability, generally can accommodate current levels of peak-period demand. Sufficient capacity exists in some regions to allow the transportation of significant additional volumes during the nonpeak periods.

Network Expansion

Increases in demand and the need for additional operational flexibility under open-access programs led to substantial expansion of the interstate pipeline system during the past several years.[48] Interregional capacity on the interstate natural gas pipeline system increased by 14 percent, or more than 10 billion cubic feet per day between 1990 and 1994 (Table 5).[49] The total cost of new pipeline development and expansion during the period is estimated at about $6.5 billion.[50] The new capacity targets the anticipated growth in natural gas demand in the Western and Northeast regional markets. The expansions provide greater accessibility to supplies in western Canada and in the Central and Southwestern States of Utah, Colorado, and New Mexico.

Capacity from Canada grew from 6.3 to about 10.0 billion cubic feet per day, an increase of 59 percent. Capacity from Canada into the Northeast Region alone rose by 357 percent. Capacity from the Central to Western regional markets also increased dramatically, 219 percent (Table 5), while capacity to the Southwest increased more modestly, 23 percent. Some of the 36-percent increase from the Central to the Southwest Region actually reflects additional deliverability directed toward the western market.

While only a few relatively small expansion projects were completed in 1994, adding less than 1 percent of new interregional capacity, currently more than 40 new or expansion pipeline projects of varying sizes are under construction or before the FERC for consideration (Figure 7). These projects, if completed, would add an additional 6.0 billion cubic feet per day of capacity to current interregional capabilities. This represents a potential increase of 7 percent over levels at the end of 1994 (Table 6).

Proposed intraregional projects represent a potential 9.7 billion cubic feet per day of additional capacity. Whereas the emphasis in the 1970's and 1980's was on long-haul pipeline development projects, in today's marketplace the greater focus is on upgrading existing pipes and adding compressor stations and looping at strategic points and segments. Localized pipeline deliverability is also being improved with the installation of new laterals to link to and attract new customers in local markets with new services and added interconnections.

Expansion plans, however, may change if customer commitments fall short or potential customers drop out in the face of project delays and/or changes in market conditions. As more capacity becomes accessible and available in the capacity release market, the need for new capacity in some regions may be reevaluated and reduced. In fact, some pipeline customers are already relinquishing expiring contracted capacity rights seeking to place this service, in part, on the capacity release market.[51]

Plans may be affected by continuing evolution of the industry. Under FERC Order 636, pipeline companies are encouraged to assume more risk on new projects and are to allocate the costs associated with new projects more directly to the customers benefiting from the expansions.[52] Some of the proposed expansion projects, therefore, may not materialize, and others

[48]Additional detail on regional pipeline expansion projects is presented in Appendix B to this chapter.

[49]Interregional capacity is defined as the capability to deliver gas to regional distribution networks from supply areas as measured at regional boundaries.

[50]Based on estimates of pipeline construction costs accompanying filings with the FERC or trade press announcements and compiled in the Energy Information Administration's Office of Oil and Gas Natural Gas Pipeline Construction Monitoring database, as of May 1995.

[51]Southern California Gas Company (SoCal) will be turning back 457 decatherm per day of capacity to Transwestern Pipeline Company when its current contract expires in November 1996 (FERC Docket RP95-271). Similarly, SoCal is seeking to turn back 300 million cubic feet per day to El Paso.

[52]Under Order 636, the cost of expansion was to be passed on to the customers who benefit from the new facilities. In certain cases this has meant that some expansion costs are only charged to incremental customers. On May 31, 1995, FERC issued its "Pricing Policy for New and Existing Facilities Constructed By Interstate Natural Gas Pipelines." The principal goals of this policy are to provide the industry with as much up-front assurance as possible with respect to the rate design to be used for an expansion, while providing for a flexible assessment of the relevant facts of a specific project (see Chapter 2, "Incremental vs. Rolled-in Rates).

Table 6. Pipeline Capacity Additions, Actual (1991-1994) and Planned (1995-1998)
(Million Cubic Feet per Day)

Capacity Additions 1991-1994									
Receiving Region	**Capacity 1990**	**Capacity 1991**	**Added Capacity 1991**	**Capacity 1992**	**Added Capacity 1992**	**Capacity 1993**	**Added Capacity 1993**	**Capacity 1994**	**Added Capacity 1994**
Canada	1,277	1,277	0	1,719	442	1,999	280	2,159	160
Mexico	399	889	490	889	0	889	0	889	0
Central	11,985	12,390	405	12,422	32	12,658	236	12,658	0
Midwest	22,818	23,300	482	24,068	768	24,148	80	24,355	207
Northeast	9,821	10,481	660	10,917	436	11,423	506	11,721	298
Southeast	20,119	20,802	683	21,076	274	21,467	391	21,587	120
Southwest	1,968	1,991	23	2,218	227	2,409	191	2,430	21
Western	7,111	7,111	0	8,841	1,730	10,060	1,219	10,061	0
Total	75,498	78,241	2,743	82,150	3,909	85,053	2,903	85,858	806

Planned Capacity Additions 1995-1998								
Receiving Region	**Estimated Capacity 1995**	**To Be Added 1995**	**Estimated Capacity 1996**	**To Be Added 1996**	**Estimated Capacity 1997**	**To Be Added 1997**	**Estimated Capacity 1998**	**To Be Added 1998**
Canada	2,309	150	2,314	5	2,314	0	2,314	0
Mexico	889	0	1,389	500	1,693	304	1,693	0
Central	12,658	0	13,377	719	13,377	0	13,377	0
Midwest	24,713	358	24,713	0	25,873	1,160	25,873	0
Northeast	11,836	115	11,886	50	12,136	250	12,136	0
Southeast	21,960	373	22,235	275	22,465	230	22,875	410
Southwest	3,030	600	3,030	0	3,030	0	3,030	0
Western	10,122	62	10,574	452	10,574	0	10,574	0
Total	87,517	1,658	89,518	2,001	91,462	1,944	91,872	410

Sources: Energy Information Administration (EIA). **1990-1994:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database as of August 1995. **1995-1998:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Monitoring Database as of August 1995, compiled from industry trade press and filings with the Federal Energy Regulatory Commission.

may be downsized or abandoned altogether.[53] In addition, the growing use of capacity release has lessened the need for additional construction.

A motivation for additional capacity expansion may have been the drive to promote new markets by offering more Transmission Company, also have proposed a similar packet service to support their northeastern market.

Market Hub Developments

Market centers, the so-called "hubs," evolved out of shippers' needs to gain access to alternative pipeline routes. Hubs have been an important development in the growth of natural gas markets. Hubs promote use of natural gas supplies by bringing buyers and sellers together in one location and by providing such services as: (1) arranging for customers to exchange gas

[53]In 1994, several major proposed projects were either downsized, canceled or postponed, or withdrawn from the FERC approval process: for example, 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.

and balance loads, (2) tracking exchanges of gas across the hub, (3) performing credit checks, (4) guaranteeing hub transactions, and (5) filing and reporting transaction information.[54] Market hubs clearly are a product of the movement to less regulation in light of their relatively recent beginnings. One of the oldest is the Henry Hub in Erath, Louisiana, founded in 1988. Deliveries through a futures contract are made at this hub.

There were only a few market hubs scattered throughout the United States in 1991. Today at least 24 operational hubs are located in the United States and 5 in Canada (Figure 8). Not surprisingly, 10 are located in Texas and 5 in Louisiana, States where hub points naturally exist because of their predominance of production and storage sources and transportation capacity. Recent new construction projects are addressing the growing need for local market deliverability and increased capacity and/or interconnections at or near hub transfer points. In addition, six more sites have been proposed, their eventual fate to be decided by the market.

It is still difficult to identify any significant influence that market hubs have had on transportation flows, although they generally are recognized as being important to the increased efficiency of the industry. Major efficiency advantages are gained through improved information, better use of the transportation network, and mitigation of the impact of increased demand on field production. Various transaction services are offered at hubs supporting the trade of natural gas. If hubs are operating effectively, these services are offered at transparent prices within markets where the bid and offer prices for gas, transportation, and storage rights are similar. The use of hubs can produce great savings if it results in reduced firm transportation requirements. Hubs also support more effective use of storage.

Market hubs are expected to increase the efficiency of the market itself. Market hubs are expected to reduce the difference in the cost of gas between market hubs that is not attributable to differential transportation costs, provided that no company can exercise significant market power. Not surprisingly, many analysts see the development of an interconnected network of market hubs as the next key step in the further integration of the industry into a "seamless" North American grid in which gas at one location will be readily substitutable or transferable for gas at other locations.

Nearly all of the physical services available at market hubs—including short-term gas sales, parking of gas for short periods of time, loaning of gas, and balancing or adjusting amount purchased or sold with amount taken or delivered—involve storage in some way. The development of hubs and the change in the general regulatory climate has increased the importance of storage, so that today underground storage is both a vital and strategic part of the natural gas industry. In 1988, while storage was a vital source of gas for reliably serving customer needs during the heating season, it was not used, as it is now, to take advantage of market movements.

[54]The INGAA Foundation, Inc., *Profile of Underground Natural Gas Storage Facilities and Market Hubs* (Washington, DC, 1995), p. III-1.

Conclusion

It is clear that Federal legislation, policies and regulations have deep influences on numerous aspects of natural gas production, delivery and consumption. These influences extend from initiatives that affect decisions on resource exploration to those that affect the quantity of gas that consumers are likely to use to heat their homes and businesses. Moreover, influential Federal initiatives are not limited to those that are specifically tailored to natural gas or even energy decisions because steps intended to protect the environment, to preserve public health and safety, to encourage economic development, and to promote monetary stability may also have indirect effects on natural gas markets and delivery systems.

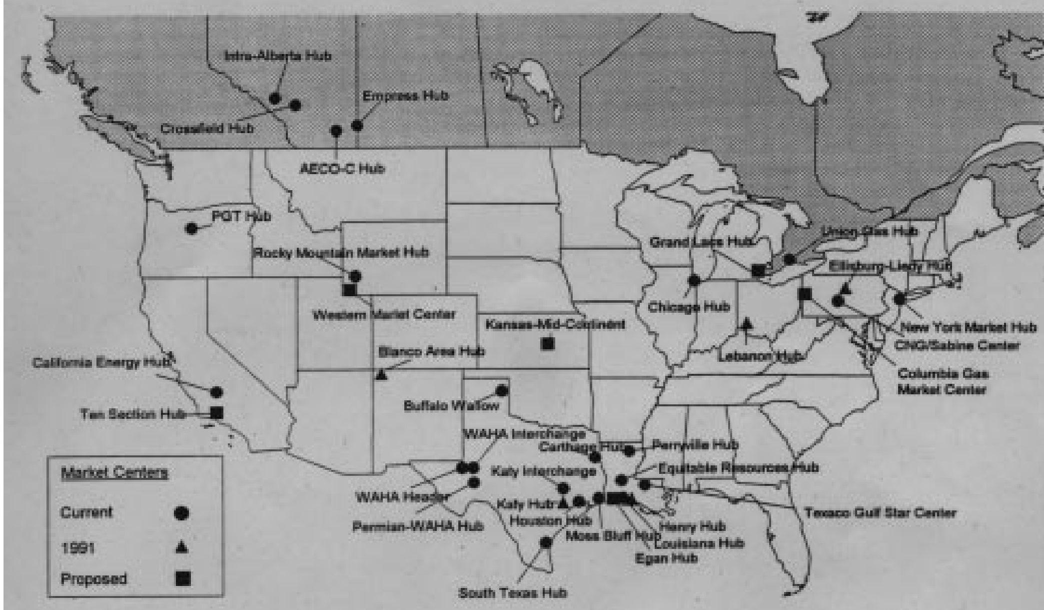
The restructuring of the natural gas industry to more open and flexible gas markets has created both shifts in demand and availability of supplies. Natural gas flow patterns have adjusted to accommodate these changing requirements, and this has led to new pipeline routes and additional pipeline capacity. For instance:

- The greatest change has been in the development and expansion of pipeline systems designed to accommodate increased access to Canadian supplies. Since 1990, import capacity has increased almost 60 percent. About 65 percent of the additional flows seen over the period went to the Western Region and Northeast markets.

- Domestically, transportation flow patterns have not changed greatly but some individual routes have grown significantly. The largest change in flow has occurred from the Central Region to California to support the enhanced oil recovery activities.

- Development of new domestic production fields, such as in the offshore Mobile Bay, Colorado, and northern New Mexico, has brought about new and expanded pipeline service from these areas. Tight formation and coalbed natural gas production from Colorado and New Mexico were stimulated by the Section 29 tax credit. Substantial production increases in other areas, such as the Hugoton field in Kansas, were the result of changes in infill drilling allowances.

Figure 8. Locations of Major Existing and Planned Market Hubs in the United States and Canada



Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Market Hubs Database, as of August 1995.

- Market/supply hubs and increasing pipeline network integration have also provided the needed flexibility to facilitate the routing of gas supplies to growing market areas and accommodate cyclical shifts in market demand and supply. The growth in industrial consumption is especially impressive in regions such as the Northeast, for example, where pipeline expansions and Canadian import availability have produced annual consumption growth rates as high as 9 percent between 1988 and 1993.

Forecasts presented in EIA's *Annual Energy Outlook 1995* integrate the influences, Federal and other, that affect natural gas activities. These projections suggest that annual natural gas consumption could reach 22 trillion cubic feet by the year 2000. This level of consumption would match the peak levels of gas consumption experienced in the early 1970's and could rise by an additional 1 trillion cubic feet by 2005. Much of this projected growth in natural gas consumption is forecast to serve electric generation markets. Throughout the country, electric utilities, industrial cogenerators, and independent power producers have made commitments to natural gas pipeline expansion projects. Indeed, these commitments are key supports for pipeline companies in obtaining regulatory approval to build facilities.

Not only will sufficient transmission capacity need to be available to move needed supplies from the field to the ultimate customer, but sufficient ancillary facilities will also have to be provided. The current level of proposed capacity additions, 9.7 billion cubic feet per day, would allow more than 3.5 trillion cubic feet per year of additional end-use consumption. Thus, expanded capacity is projected to be more than sufficient to serve consumption growth over the next 5 years. Storage additions are expected to provide about 20.7 billion cubic feet by 1998, the equivalent of 7.6 trillion cubic feet per year of extra service. The pipeline expansions, combined with storage capability additions, should provide adequate gas to serve customers needs.

4. Trends in Natural Gas Transportation Rates

This chapter discusses trends in natural gas transportation rates for the period 1988 through 1994 and how Federal regulations and policies affect those trends.[55] Regulatory reform, new legislation, and restructuring in the natural gas industry have expanded options for sellers and buyers of natural gas, resulting in increased competition within the industry. Buyers now have more choices for purchasing gas, and ancillary services such as pipeline transmission and storage rights. Suppliers have a wider range of prospective customers and greater flexibility in setting the terms of sale. This competition has contributed to higher gas throughput on the interstate pipeline system and lower average transmission prices (Figure 9).[56] From 1988 through 1994, deliveries to end users increased 16 percent, while average transmission markups declined 16 percent, from $1.49 to $1.25 per thousand cubic feet. In the face of increasing competition, many segments of the industry have become more efficient and reduced costs, to the general benefit of consumers.

Natural gas consumers have benefited in two ways. First, the wellhead price of natural gas, effectively the price of the commodity itself, has declined substantially. Between 1988 and 1994, the average wellhead price of natural gas, in real terms, fell 11 percent, from $2.05 to $1.83 per thousand cubic feet. Average prices paid by some customer classes, specifically onsystem industrial and electric utility customers, have declined even more than the decline in the wellhead price, indicating that additional benefits have been obtained from lower costs of transmission and other delivery services. Residential and commercial customers, who for the most part obtain all of their service from local distribution companies, have not experienced significant reductions in the costs of service beyond the decrease in wellhead prices. Although these customers have paid less for transmission, distribution costs have increased resulting in little overall change.

In total, EIA estimates that consumers paid almost $6.5 billion (9 percent) less, in real terms, for natural gas service (including wellhead purchases combined with transmission and distribution charges) in 1994 than they would have in 1988. This estimate includes $2.5 billion in reduced transmission and distribution charges and $4 billion of savings resulting from the 11-percent reduction in wellhead prices since 1988. The bulk of the $2.5 billion represents the reduction in the fixed costs of transmission and distribution that do not vary with the volumes delivered. Because of data limitations, the estimate of total savings may be low because for offsystem industrial customers only the savings in wellhead prices are included. However, of the $6.5 billion savings, industrial customers were the main beneficiaries, receiving overhalf of the savings ($3.8 billion), while electric utilities and commercial customers each saw savings of $1.4 billion.

Another way to estimate savings is to compare the average price per thousand cubic feet to each end-use sector in 1994 and 1988. This method assumes that transmission and distribution costs would vary with the volumes delivered. In 1994, the price of 1 thousand cubic feet of gas (wellhead price plus delivery charges) to the end-use sectors was between 3 and 19 percent less than 1988 levels. The differential in savings stems from the range of prices different customer groups pay for natural gas deliveries. The prices are based on a number of elements, particularly the level and quality of service required.

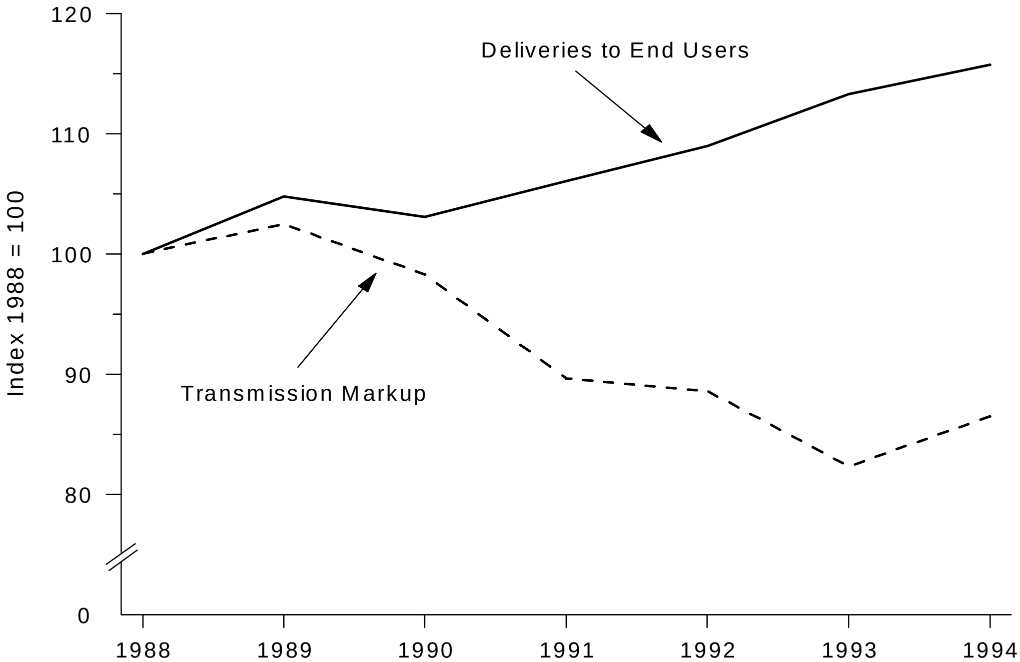
The analysis in this chapter focuses only on the costs associated with the delivery of natural gas from the wellhead to the end user. Interstate pipeline companies transport gas from the supply areas to serve some customers directly, but much of the gas they transport is to the "citygate" of a local distribution company (LDC). LDC's then provide the distribution and other services needed to supply homeowners, commercial establishments, and other customers. The interstate pipeline companies are regulated at the Federal level, and the extensive regulatory changes caused by Orders 436 and 636 have directly affected the rates they charge. LDC's are regulated at the State level, and while some changes are being made at the State level comparable to the Federal level, there have not been extensive changes to date.

As discussed in Chapter 1, there are no publicly available data series on the actual prices paid by shippers on interstate pipeline companies. The information available relates only to the tariff rates (maximum rates) authorized by the Federal Energy Regulatory Commission (FERC). The analysis of transportation rates in this chapter uses several approaches, both qualitative and quantitative, to illustrate how transmission costs have been affected by legislative and regulatory changes. Sections of the chapter address:

[55] All rates and prices are quoted in terms of real 1994 dollars.

[56] The transmission markup is calculated as the difference between the average citygate price and the average wellhead price. The transmission price (or markup) represents the average price paid for all services required to move gas from the wellhead to the local distributor. The data reflect the prices paid for gas sales services provided by LDC's only.

Figure 9. Indices of Natural Gas Transmission Markups and Deliveries to End Users, 1988-1994



Sources: Energy Information Administration, Office of Oil and Gas, derived from: **1988:** *Historical Monthly Energy Review 1973-1992* (August 1994). **1989-1994:** *Natural Gas Monthly* (August 1995).

- **Factors affecting interstate transportation rates**. To understand how changes in laws and regulations can affect transportation rates, it is useful to look first at how rates are structured. This section first describes some of the key determinants used to develop interstate transmission rates and how economic and regulatory changes between 1988 and 1994 have affected the calculation of the rates. In addition, as the restructuring of the industry proceeded over the period addressed by this study, FERC implemented mechanisms for companies to recover costs associated with the restructuring, such as reformation of contracts, stranded investments, and other transition costs. Finally, the effect of the more competitive environment on rates charged by pipeline companies is briefly addressed.

- **Trends in maximum rates for selected interstate corridors** (Corridor Rate Analysis). Some indication of the overall movement in transportation rates over time can be obtained from looking at changes in the maximum rates charged by pipeline companies. This section looks at rates for 16 pipeline companies along 14 corridors. However, because pipeline companies often discount rates, the rates actually paid by many customers may be substantially less than the maximum rate approved by FERC.

- **Impact of revenue from pipeline capacity release in offsetting payments for capacity reservation**. Shippers holding capacity rights on interstate pipelines may release that capacity in the secondary capacity market if they do not need it. Revenues obtained from that capacity release are not reflected in the overall maximum rates discussed earlier, even though they lower the overall cost of shipping gas.

- **Changes in transmission markups at the national and regional levels**. A more aggregate measure of trends in transmission markups can be obtained by comparing the differences between wellhead, citygate, and end-use prices. Because of the options available to customers to use alternative transmission routes, analyzing rates along specific corridors may miss the impact of the increased flexibility available to customers. This section examines markups from the wellhead to the local distribution company and from the citygate to the end user, at both the national and regional levels.

Factors Affecting Interstate Pipeline Transportation Rates

Pipeline company tariff rates for interstate transportation services are determined using the traditional cost of service approach. The maximum (tariff) rate that a pipeline company can charge a particular customer is determined by several factors. The key determinants are: the rate base, the allowed rate of return on the rate base, the level of operating costs, the amount of capacity reserved, the load factor, the expected level of interruptible throughput, and the rate design (see Appendix D for additional information on the determinants of rates). This section discusses the impact of each of these determinants in isolation, that is, assuming all other factors remain constant. A quantitative assessment of the trend in each factor is also presented.

- **Rate base.** The rate base is the historical cost of physical capital on which the pipeline is entitled to earn a return. The rate base is generally calculated as net plant in service (gross gas plant in service plus construction work in progress less the accumulated depreciation, depletion and amortization) plus prepayments and inventory less accumulated deferred income taxes. Depreciation of the physical assets in service and abandonment or sales of existing plant lowers the rate base over time and will lower the maximum rate that pipeline companies are allowed to charge. However, this effect is offset by any investment in new capacity or the refurbishment of existing capacity which increases the rate base, and the maximum allowable rates.

  The 1988 through 1994 period was marked by a significant amount of new pipeline construction. As a result, the costs of new construction more than offset the effect of depreciation for the industry-wide rate base reflecting the physical capital used in providing transmission services. This new construction was undertaken for a variety of reasons, including hooking up new sources of supplies (both domestic and imports) and meeting the requirements of a 13 percent increase in consumption. As a result of this investment, the total rate base for the major pipeline companies grew, in nominal dollars, from $20.2 billion in 1988 to $25.6 billion in 1994 (Table 7).[57] One would expect rates to have increased over this period because of the increase in the rate base.

- **Approved rate of return.** The allowed rate of return (or the cost of capital), approved by FERC for each pipeline company, is a weighted average of the firm's cost of debt and the rate of return on equity as determined by the regulatory process. FERC examines a number of elements in determining the rate of return for a particular pipeline company, including capital structure, risk conditions, and other factors. Modifications to a pipeline company's approved rate of return alter its total cost of service, which, in turn, can lead to changes in that company's maximum rates for transportation services. From 1988 through 1994, approved rates of return for pipeline companies decreased, partly because their marginal cost of debt declined, as reflected by generally lower interest rates. For example, the rate for AA utility bonds declined from 10.26 to 8.21 percent. During this period, the decrease in the average approved rate of return for pipeline companies was more modest than the reduction in interest rates. One possible explanation is the relatively higher interest costs paid by the pipeline companies as a result of their low bond ratings.[58] Specifically, the settlement rates of return were largely flat at about 11.5 percent during most of the period but did decline in 1994 to approximately 10.2 percent[59] (Figure 10).

- **Operation and maintenance (O&M) expenses.** These are the direct costs of operating and maintaining pipeline facilities necessary to keep the system operational. O&M costs are reviewed as part of a rate hearing and any increases approved by FERC can be expected to result in higher rates. Changes in these costs that were not anticipated at the time of the rate hearing are not addressed until the next hearing and therefore do not affect the approved rate in the interim. As a result of the increased competition under open access, pipeline companies appear to have become more efficient, as evidenced by reductions in operating costs and administrative and general expenses and increases in employee productivity (measured by natural gas deliveries per employee).[60] Between 1988 and 1994, O&M costs declined in 1994 dollars from $8.5 billion to

[57]Rate base trends, only, are stated in nominal dollars to conform to the ratemaking process of computing rates. However, the return on rate base is converted to constant dollars to agree with other discussions.

[58]For additional information, see Energy Information Administration (EIA) report, *Natural Gas 1994: Issues and Trends*, DOE/EIA-0560(94) (July 1994).

[59]It should be noted that the rates cited represent only those revised rates that FERC approved ("settlement cases") during the year and hence, do not necessarily represent the entire industry. The number of settlement cases during 1993 and 1994 was 12 and 13, respectively, considerably below the 16 to 18 cases per year between 1989 and 1992.

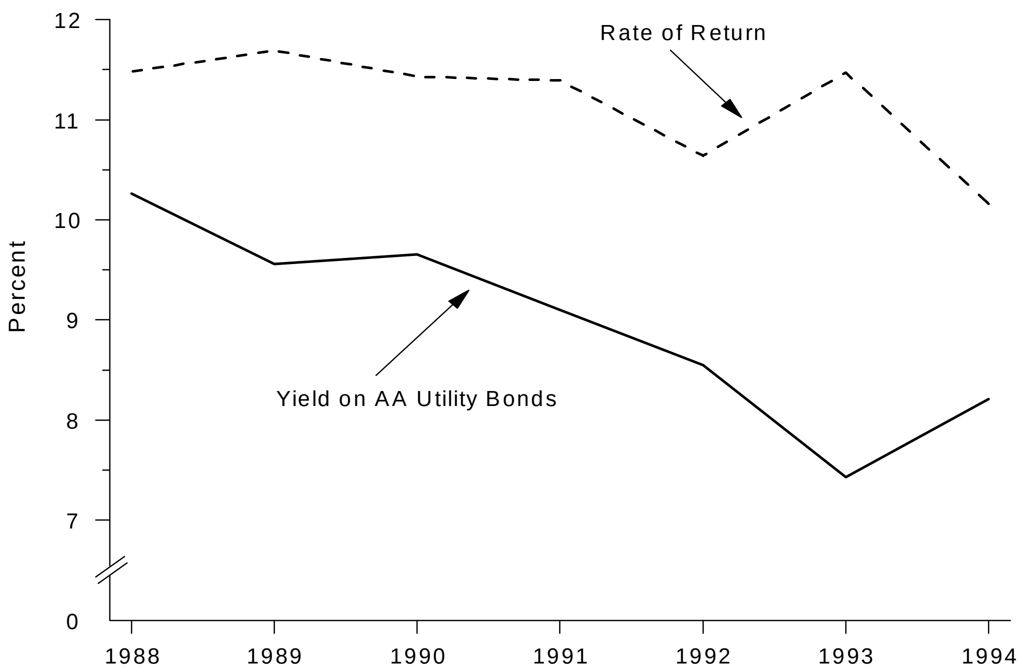
[60]For additional information, see the EIA report, "Natural Gas 1995: Issues and Trends," DOE/EIA-0560(95), to be published in the fall of 1995.

Table 7. Composite Rate Base, 1988-1994
(Billion Nominal Dollars)

Rate Base Elements	1988	1989	1990	1991	1992	1993	1994
Rate Base							
Gas Plant in Service	44.3	44.2	48.8	52.7	52.3	54.3	55.1
Accumulated Depreciation	26.1	26.5	28.1	30.5	28.6	29.7	29.7
Net Plant in Service	18.2	17.7	20.7	22.2	23.7	24.7	25.4
Additions to Rate Base	8.3	7.4	8.5	8.9	7.8	6.9	5.9
Subtractions from Rate Base	6.3	6.1	6.0	5.4	5.2	5.5	5.7
Total Rate Base	20.2	18.9	23.2	25.7	26.3	26.1	25.6

Note: Construction work in progress is included in additions to rate base.
Sources: **1988-1989:** Energy Information Administration, *Statistics of Interstate Natural Gas Pipeline Companies 1990* (April 1992). **1990-1994:** Federal Energy Regulatory Commission (FERC) Form 2. "Annual Report of Major Natural Gas Companies," Balance Sheet File from FERC Gas Pipeline Data Bulletin Board System.

Figure 10. Average Yield on AA Utility Bonds and Rate of Return for Interstate Pipeline Companies, 1988-1994



Note: The rate of return represents the average settlement rate of return approved by the Federal Energy Regulatory Commission.
Sources: **Yield on AA Utility Bonds:** Moody's Investor Service, Inc., extracted from DRI History file: USQ0993.WS. **Rate of Return:** Federal Energy Regulatory Commission, Office of Pipeline Regulation.

$5.4 billion (Table 8). In addition to efficiency improvements, falling O&M costs may be the result of several factors including technology improvements and the spin-off of pipeline facilities.

- **Load profile.** The load profile of a pipeline customer is indicated by its load factor, which is simply the ratio of its average (usually, the annual average) level of pipeline throughput to the maximum pipeline capacity it has reserved. Shippers with relatively large load factors are said to have higher load profiles, while relatively smaller load factors equate to lower load profiles. For example, local distribution companies that serve residential and commercial customers must reserve sufficient pipeline capacity to satisfy the wintertime peak demands for these customers, even though their off-season demand can be satisfied with substantially less capacity. Thus, an LDC's throughput averaged over the year is likely to be relatively low compared with the capacity it must reserve to meet peak demands. When this is the case, it is said to have a low load profile. The load profile affects the way in which fixed costs are assigned in computing rates. Pipeline customers with a low load factor will be charged higher average rates compared with customers with a high load factor. While this is an important consideration in determining rates, there is insufficient information regarding load profiles to provide a quantitative assessment of the impact of load factors on changes in transportation rates.

- **Capacity reserved.** An increase in the amount of capacity reserved on a pipeline tends to lower reservation rates because the fixed costs will be collected over more units of reserved capacity. Reservation charges are billed to a customer for each unit of capacity reserved, whether or not the capacity is used.[61] Data limitations do not permit a precise assessment of the trend in reserved capacity between 1988 and 1994. However, there is evidence to suggest that the amount of reserved capacity has increased. Much of the increase in deliveries to end users from 1988 through 1994 is accounted for by firm services (Figure 11).[62] While some of this increase in deliveries may be associated with higher utilization of existing reserved capacity, the overall average utilization of the pipeline system was about the same in 1991 and 1994 (see Chapter 3). The combination of increased firm deliveries and pipeline expansion during this period may indicate that the amount of reserved capacity has increased.

- **Expected level of interruptible throughput**. While interruptible rates may be lower than firm rates, interruptible throughput does contribute to fixed costs. When determining tariff rates, fixed costs are allocated between firm and interruptible services based on their respective loads on the pipeline.[63] The interruptible customers' load is estimated from their forecasted annual throughput level. As a result, an anticipated decrease in the level of interruptible throughput raises firm transportation rates by increasing the level of fixed costs allotted to firm transportation services. Interruptible throughput declined over the 1988 through 1994 period (Figure 11) putting upward pressure on firm transportation rates.

- **Rate design.** Firm customers pay a reservation charge to reserve pipeline capacity as well as a charge based on the amount of gas actually transported. Rate design refers to how fixed costs are allocated and collected in these two charges. From 1988 through 1991, the modified fixed-variable (MFV) rate design was widely used. Under this system, fixed costs were allocated to both the reservation and volumetric components of rates. FERC Order 636 stipulated the use of the straight fixed-variable (SFV) rate design. Under this method, all fixed costs are allocated to the reservation charge, while variable costs are allocated to a commodity or usage fee (Figure 12). This change in rate design tends to increase rates for low-load-factor customers and decrease rates for high-load-factor customers (see Chapter 2). The change to SFV reallocated approximately $1.7 billion from the usage fee to the reservation fee.[64]

- **Take-or-pay costs**. Contract reformation costs resulting from take-or-pay settlements associated with the implementation of Order 436 have totaled approximately

[61] If a customer requires 1 million cubic feet (MMcf) of gas on a day during the month of January (assuming the pipeline company does not offer seasonal rates), that customer must reserve 1 MMcf of space on the pipeline for every day during the year.

[62] Besides traditional firm service, this includes 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.

[63] The firm service load is derived from the amount of space firm service customers reserve on the pipeline or the measured load firm service imposes on the pipeline system during the period of maximum use.

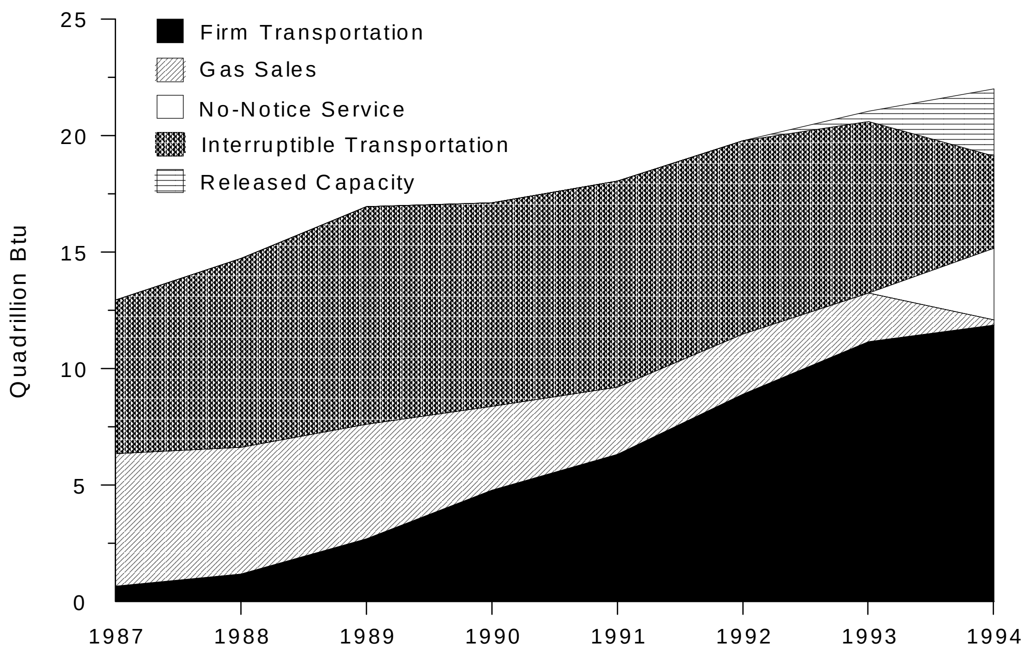
[64] Monetary estimate from the Federal Energy Regulatory Commission, Order 636-A, footnote 314, 57 F.R. 36128,36173 (1992). Actual costs paid by any class of customers depend on the discounts from the maximum allowable rates that may be obtained from the pipeline company.

Table 8. Composite Cost of Service
(Billion 1994 Dollars)

Elements	1988	1989	1990	1991	1992	1993	1994
Return on Rate Base	2.8	2.6	2.9	3.1	2.9	3.1	2.6
Operation and Maintenance Expenses	8.5	9.3	6.1	9.0	7.5	6.9	5.4
Other Expenses	3.4	3.2	3.1	2.4	3.0	3.3	3.1
Total Cost of Service	14.6	15.1	12.2	14.6	13.4	13.3	11.1

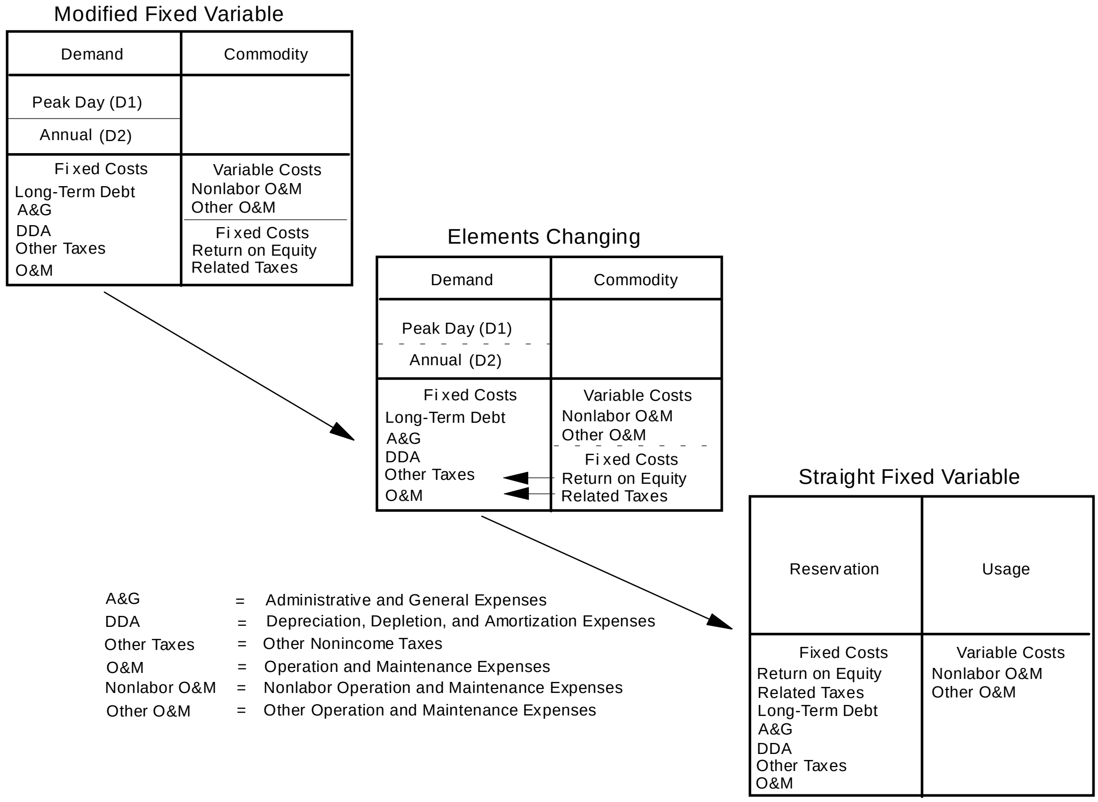
Note: Return on Rate Base = Total Rate Base multiplied by FERC Approved Rate of Return.
Sources: **1988-1989:** Energy Information Administration, *Statistics of Interstate Natural Gas Pipeline Companies 1990* (April 1992). **1990-1994:** Federal Energy Regulatory Commission (FERC) Form 2. "Annual Report of Major Natural Gas Companies," Balance Sheet File from FERC Gas Pipeline Data Bulletin Board System.

Figure 11. Natural Gas Transmission by Type of Service, 1987-1994



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

Figure 12. Rate Design in Transition: Modified to Straight Fixed Variable



Source: Energy Information Administration, *Natural Gas 1992: Issues and Trends*.

$10.2 billion as of May 30, 1995.[65] Pipeline companies have agreed to absorb about $3.7 billion. Of the remaining $6.6 billion, $3.6 billion is being recovered through a surcharge on firm transportation customers and the remainder is being recovered through a surcharge on volumetric rates. Recovery of these take-or-pay costs began in the late 1980's and is expected to result in higher rates for some customers throughout the 1990's.

- **Transition costs**. As of August 1995, $2.7 billion in transition costs associated with Order 636 have been filed at FERC for recovery through increased transportation rates to shippers.[66] The $2.7 billion of costs include $1.4 billion of gas supply realignment costs; $0.6 billion of unrecovered gas costs; $0.7 billion of stranded costs, and $9 million for new facilities. Additional transition costs are likely and will probably affect rates for the next 3 to 5 years.

- **Costs of pipeline expansion**. For the period 1991 through 1994, the interstate pipeline companies spent $6.5 billion on expanding interstate pipeline capacity. Expansion costs generally have been passed through to all customers and will continue to influence transportation rates, because they are amortized over many years. Pipeline expansion costs increase the rate base and, subsequently, transportation rates.

Changes in the elements described above for determining rates offset and counterbalance each other. The rate design, which determines how costs are allocated and recovered from customer classes, probably has the most significant direct impact on rates. In addition, industry restructuring has resulted in significant costs associated with the changes implemented in the new regulations, including more than $10 billion in take-or-pay costs under Orders 436 and 500, and an additional $2.7 billion in transition costs associated with Order 636.

When Order 636 shifted the responsibility and risk of maintaining service from the interstate pipeline companies to the local distribution companies and consumers, the allocation of costs for some services changed. For example, a charge that was previously included in the price paid for interstate transmission

[65] A contract provision obligating the buyer to pay for a certain minimum quantity of product, whether or not the buyer takes that quantity during the stated period.

[66] Shippers include any customer who uses transportation services.

service may now be included in the distribution costs (or it may be paid directly by the end user and hence not reported by either the interstate pipeline or the local distribution company). This can affect the accounting (and reporting) of both the costs of long-haul transportation (by interstate pipeline companies) as well as local delivery charges (by local distribution companies). For this reason, only aggregate costs of transmission and distribution service are examined for some of the areas analyzed. In addition, firm transportation rates previously may have included a number of other services, such as storage and load-balancing. In this analysis, it was not possible to adjust the data to reflect a consistent definition over time. Therefore, trends in transportation rates may only be approximations.

The difficulty of differentiating distribution from transmission costs presents additional problems when analyzing the effects of Federal policies and regulations on transportation rates. Distribution rates charged by local distribution companies are regulated by State utility commissions not by FERC. Recently, some of the larger consuming States have been experimenting with various types of rate designs, such as market- and incentive-based rates, to introduce greater competitive forces into the distribution system. Some States are even advocating that LDC's unbundle their services.

Because of these and other data limitations, this analysis does not attempt separately to attribute specific changes in transportation rates to specific Federal legislation or regulations. Rather, the chapter presents general trends in transmission rates, showing how they are influenced in aggregate by regulations, legislation, and policies, as well as economic and market elements.

The Corridor Rate Analysis

A number of regulatory and market influences affected rates over the 1988 through 1994 period. One of the most significant regulatory changes that has had a direct impact on rates is FERC Order 636 and the resulting change in rate design to the straight fixed-variable (SFV) method. The analysis of transportation corridors examines the change in maximum transportation rates under Order 636 but does not isolate the changes in rates due exclusively to the SFV rate design. Rather, it assesses the net effect on transportation rates of all of the regulatory and market influences, including rate base changes, operating costs, taxes, depreciation, interest rates, capacity reserved, load profiles, rates of return, etc.

The analysis compares maximum firm transportation rates, including surcharges (tariff rates) charged before and after Order 636 went into effect. Although maximum rates may not apply to customers who pay discounted rates for services, pipeline company core customers generally pay maximum tariff rates. Therefore, the analysis of maximum rates will provide a basis on which to gauge the general movement of firm transportation rates. The tariff rates analyzed include surcharges such as Order 636 transition costs.

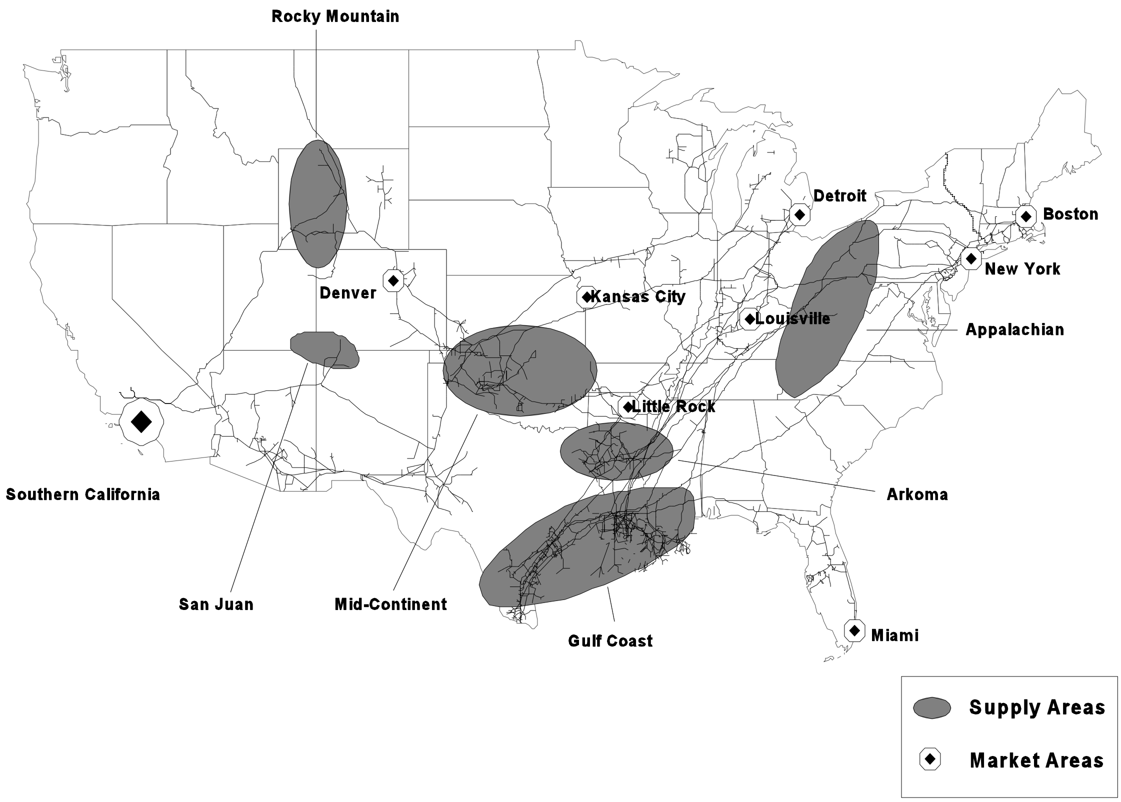
Firm transportation rates in 1994 were compared with rates in effect in 1991 for a sample of 14 supply/demand areas or corridors (Figure 13). The 16 companies represented in the sample have a combined service area that spans the country and a throughput level that is almost half the total industry throughput. The sample of corridors was developed based on the market corridors presented in the Foster Associates' December 1994 publication *Competitive Profile of Natural Gas Services* (discussed in more detail in Chapter 5).[67] For any single corridor in the sample, there may be several routes, with each route representing the transportation services of one or more pipeline companies. For instance, the corridor from the Gulf Coast supply area to the Boston market area includes two separate routes: (1) Texas Eastern Transmission Company and Algonquin Gas Transmission Corporation and (2) Tennessee Gas Pipeline Company. An aggregate or "unit" rate, representing the total transmission charge for moving 1 million Btu (MMBtu) of gas, was developed for each of the 21 routes in the sample. The results from the rate analysis are presented in constant 1994 dollars.

The analysis compares the unit cost for firm (i.e., noninterruptible) transportation service, defined as the charge for transporting one unit (MMBtu) of gas, for two types of customers:

- **High-load-factor** customers tend to transport gas at a constant level throughout the year. These customers impose a daily demand on the system that is about equal to the average of their annual volume transported. For example, a high-load-factor customer who transports 365 MMBtu of gas per year will tend to transport about 1 MMBtu of gas per day. The industrial customers, such as an aluminum plant or food processing plant, with a high load factor tend to have gas requirements that are related to manufacturing needs as opposed to the seasonal demand for space heating. Some electric generators may have uniform usage throughout the year and thus be characterized as high-load-factor customers.

[67]The pipeline routes and companies in the sample were chosen for the analysis because they have a diverse load profile, have a geographically dispersed service area, and have readily available tariff schedules. The pipeline routes account for 43 percent of total U.S. throughput. See Appendix E for additional information including the names of pipeline companies included in this analysis.

Figure 13. Interstate Transportation Corridors Used in Corridor Rate Analysis



Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System.

- **Low-load-factor** customers do not take gas at a constant rate throughout the year. These customers have a peak daily usage that far exceeds the average of their annual use. Residential and commercial sectors are generally low-load-factor customers because they depend on natural gas as a space-heating fuel. Their demand tends to fluctuate with weather temperature. Hence, the pipeline company must be prepared to meet the load requirement of these customers up to the maximum amount of capacity reserved even though the maximum load may occur only a few times a year.

The comparison of load factor rates illustrates the effect of the switch from the modified fixed-variable (MFV) rate design to the straight fixed-variable (SFV) rate design. As discussed earlier in this chapter, many elements affect rates for pipeline service. Except for the change in rate design to SFV, each element will have the same general effect on customers regardless of their load factor. However, the switch from MFV to SFV rate design will tend to have a different impact on maximum tariff rates depending on the load factor, increasing low-load-factor rates while decreasing high-load- factor rates. (For additional information see Chapter 2.)

For this analysis a 100-percent load factor was used to represent high-load-factor customers and a 40-percent load factor for low-load-factor customers. The 40-percent load factor assumes that the low-load customers will impose a peak-day load on the system that is two and one half times the customers' average daily requirements. The load factors were selected for purely illustrative purposes. Actual load factors for shippers may vary from these assumed levels, depending on their service requirements throughout the year. For local distribution companies, this will depend on the mix of residential, commercial, industrial, and electric utility customers and their service requirements.

The average unit rate paid by 100-percent and 40-percent load-factor customers will vary depending on the level of the pipeline company's reservation charge. For example, assume that firm transportation rates include a $0.25 per MMBtu daily reservation charge and a $0.05 per MMBtu usage charge. The 100-percent load-factor customer that transports 1 MMBtu per day will pay, on average, $0.30 per MMBtu for service (1 MMBtu reservation at $0.25 per MMBtu + 1 MMBtu usage at $0.05 per MMBtu). The 40-percent load-factor customer, however, will need to reserve enough space to meet his peak requirements. If the 40-percent load-factor customer transports an average of 1 MMBtu per day, its peak requirements would equal 2.5 MMBtu (load factor = average use/peak use = 40 percent = 40/100 = 1/2.5). Therefore, the 40-percent load-factor customer will pay an average rate of $0.675 per MMBtu for service (2.5 MMBtu reservation at $0.25 per MMBtu + 1 MMBtu usage at $0.05 per MMBtu). (This simplified example ignores the seasonal rates pipeline companies may offer.)

Findings of the Corridor Rate Study

No clear pattern emerges with respect to the change in maximum tariff rates and the respective corridor, supply area, or delivery point. However, there are some noteworthy differences between the 100-percent and the 40-percent load-factor rates. As discussed earlier, the change in rate design was the one phenomenon expected to have different impacts on high- and low-load-factor customers. If the switch in rate design to SFV were the only change during the period, all high-load-factor rates would be expected to decrease and all low-load-factor rates to increase.

It appears that the conversion to SFV rate design was the dominant influence on rate changes for both high- and low-load-factor customers from 1991 through 1994. While other influences may have mitigated SFV's downward pressure on high-load-factor rates and upward pressure on low-load-factor rates, the rate design shift widened the gap between high- and low-load-factor rates. Half the sampled 100-percent load-factor corridor rates increased between 1991 and 1994, while half decreased (Table 9). For the 40-percent load-factor rates, one-third of the corridor rates decreased while two-thirds increased. This higher incidence of rate increases for the low-load customers suggests that recent regulatory changes have benefited low-load-factor customers less than high-load-factor customers. Although both categories of customers had increases and decreases in tariffs, the change was more advantageous to the high-load-factor customers. More compelling evidence is provided by inspecting the differentials in the magnitudes of the rate changes. For instance, in every case where the high-load-factor rate increased, the low-load-factor rate also increased. Moreover, in all cases, the increase was larger in both absolute and percentage terms for the low-load-factor customers. For example, the high-load-factor rate for Canada to New York increased by 4 percent while the low-load-factor rate increased by 19 percent.

In about half of the cases considered, rates to the high-load-factor customers declined, while rates to the low-load-factor customers either decreased by a smaller amount or actually increased. For example, on route A from the Gulf Coast to Boston, the 100-percent load-factor rate declined by 23 percent while the 40-percent rate declined by 8 percent. On the Gulf Coast to Louisville route, the 100-percent rate declined 18 percent. In sharp contrast, the 40-percent rate on the same route increased by 9 percent.

The results of the analysis suggest that the hypothesis that all high-load-factor customers would face decreases in transmission rates and all low-load-factor customers would suffer economically as a result of Order 636 is overly simplistic. For both sets of customers, some rates increased between 1991 and 1994 while others declined. Clearly, there are elements other than the switch to SFV that had an impact on rates during this period. What is striking, however, is the large difference between the two customer classes in terms of the magnitudes of the rate changes. On any given route, the high-load-factor customers experienced a rate change that was more advantageous than the rate change experienced by the low-load-factor customers. This has resulted in a widening of the gap between the 100-percent and the 40-percent load-factor rates between 1991 and 1994. Thus, SFV had a dominant influence on the widening gap in rates for these customer classes. As striking as these results are, they may actually understate the actual impact, because the data used in this analysis are for maximum posted rates. In reality, rates may be discounted. Discounted rates will tend to be obtained by high-load-factor customers, such as industrial customers with alternative fuel capability. Accordingly, the actual differentials in the percentage increases and decreases between the two customer classes are probably larger than those presented in this report.

In addition to the cost-of-service issues discussed earlier in this chapter, a number of regulatory elements affect rates. While rate design may have the most significant direct impact on rates, transition costs resulting from recent regulatory changes also affect rates. Order 636 transition costs include: (1) unrecovered gas costs, (2) gas supply realignment (GSR) costs, (3) stranded costs, and (4) the cost of new facilities.[68] Of these transition costs, the GSR and stranded costs are passed through to customers in the adjustment charges included in the corridor rates. These charges increase overall transportation costs for firm service customers. The cost of new facilities associated with Order 636 would tend to increase tariff rates.

[68]Federal Energy Regulatory Commission Docket No. RM91-11-002, et al., Order 636-A, August 3, 1992, p. 336.

Table 9. Estimated Maximum Rates for Firm Transportation Service on Selected Interstate Pipeline Routes, 1991 and 1994
(1994 Dollars per Million Btu)

Supply to Market Routes	100-Percent Load Factor			40-Percent Load Factor		
	1991	1994	Percent Change	1991	1994	Percent Change
Northeast Region						
Gulf Coast to Boston						
Route A	1.28	0.98	-23	2.19	2.01	-8
Route B	0.55	1.11	102	0.93	2.42	160
Appalachia to Boston						
Route A	0.88	0.74	-16	1.55	1.54	-1
Route B	0.44	0.52	18	0.73	1.14	56
Canada to Boston						
Route A	0.85	0.98	15	1.69	2.26	34
Route B	0.52	0.64	23	0.71	1.43	101
Gulf Coast to New York						
Route A	0.55	0.97	76	0.93	2.09	125
Route B	0.93	0.75	-19	1.58	1.49	-6
Route C	0.85	0.56	-34	1.48	1.03	-30
Canada to New York	0.80	0.83	4	1.69	2.01	19
Southeast Region						
Gulf Coast to Louisville	0.66	0.54	-18	1.08	1.18	9
Gulf Coast to Miami	0.38	0.55	45	0.73	1.19	63
Arkoma to Louisville	0.75	0.77	3	1.15	1.68	46
Midwest Region						
Gulf Coast to Detroit						
Route A	1.03	0.82	-20	1.82	1.80	-1
Route B	0.71	0.54	-24	1.13	1.14	1
Route C	0.43	0.55	28	0.78	1.24	59
Central Region						
Rocky Mountain to Denver	0.38	0.39	3	0.67	0.83	24
Mid-Continent to Kansas City	0.44	0.47	7	0.70	1.03	47
West Region						
San Juan to Southern California	1.04	0.80	-23	1.35	1.26	-7
Canada to Southern California	1.53	1.36	-11	1.53	2.52	65
Southwest Region						
Arkoma Basin to Little Rock	0.46	0.29	-37	0.70	0.59	-16

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **1991:** Gulf Coast to Miami—H. Zinder & Associates, *Summary of Rate Schedules of Natural Gas Pipeline Companies* (March 1991); Other corridors—Foster Associates, *Competitive Profile of U.S. Interstate Pipeline Companies* (October 1991); **1994:** Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foster Associates, *Competitive Profile of Natural Gas Services* (December 1994).

Rate increases on a particular pipeline may be caused by the loss of customers who either chose to exercise their alternative fuel capabilities or chose other transportation options. (As discussed earlier, Orders 436 and 636 opened opportunities for customers to switch service providers.) As customers leave a pipeline system, its fixed costs may be recovered by fewer customers and lower throughput volumes, leading to increased rates. Pipeline companies may also be discounting services to retain certain customers and passing on additional costs to other customers who have no other service options (captive customers). Order 636 permits pipeline companies to discount services on a nondiscriminatory basis to meet competition. In order not to discourage discounting, FERC allows the discounted "units" to be factored into the determination of maximum rates.[69]

In a competitive market, price differences across firms reflect quality and geographic (e.g., locational) differences. Price differences in excess of what can be accounted for by these elements may indicate the market's inefficiency at setting prices. On this score, the convergence in corridor rates, while not conclusive, suggests that the market for transportation became more efficient during the period 1991 through 1994.

Comparing pre- and post-Order 636 rates in the corridors served by multiple pipelines suggests that transportation services offered by different pipeline companies may have become more similar, as evidenced by a convergence in rates. In the sample, multiple routes are available within five corridors: Gulf Coast to Boston, Appalachia to Boston, Canada to Boston, Gulf Coast to New York, and Gulf Coast to Detroit (Table 10). For 100-percent load-factor rates, three out of five of these corridors showed a trend toward a convergence of rates, one corridor showed no change, and the fifth showed a modest increase in the variation of rates (Figure 14). The corridors that did exhibit convergence displayed a substantial reduction in the variation in rates. For example, for the two routes from the Gulf Coast to Boston, the rate difference for high-load-factor customers declined from $0.73 per MMBtu in 1991 to $0.13 per MMBtu in 1994 (Table 10). Particularly notable in this analysis is that low-load-factor customers have also seen a reduction in the rate variation in four out of five corridors. However, this reduced variability results from low-end rates moving up to the level of high-end rates rather than a reduction in high-end rates.

The reduced variability in rates may indicate that in addition to, or possibly as a result of competition, firm transportation services provided by various pipeline companies have become more similar. That is, notwithstanding geographical considerations, a customer may be able to substitute the transportation service offered by one company for transportation service offered by another. In addition, Order 636's directive to use a common rate design method for all pipeline companies may have led to more similarity in the rates offered by pipeline companies serving the same corridor. While intriguing, the finding of rate convergence should be interpreted with a high degree of caution given the small number of corridors on which the finding is based.

As previously discussed, the study cannot isolate numerous influences on the outcome of maximum firm transportation rates. Also, affecting the net cost of transportation is the revenue received for capacity release. Capacity release revenue credits are passed through to firm transportation customers; however, the unit decrease is not reflected in the maximum transportation rate. The extent of the released capacity's influence on transportation rates will depend on the development of the secondary market.

Capacity Releases and Transportation Rates

The capacity release program is another provision of Order 636 that has the potential to affect transportation rates directly. Prior to Order 636, capacity rights on a pipeline were nontransferable. A customer could either use the capacity itself or it would be available to the pipeline company with no compensation to the customer. Under Order 636, a shipper with excess reserved capacity can release that capacity to another shipper in return for a credit on its reservation charges.[70]

Under the capacity release program, a local distribution company (LDC) may assign to others some of its rights to capacity on the pipeline system. This would typically occur during the summer when there is no demand for space heating. If this reassignment of capacity results in new incremental load, the pipeline system will operate on a more uniform basis

[69]In other words, a pipeline company that transports 100 MMBtu of gas at half of its maximum transportation rate will develop rates assuming 50 MMBtu were transported for that service. If the transportation costs remain the same, firm transportation rates will increase because those costs will be recovered on fewer units of gas.

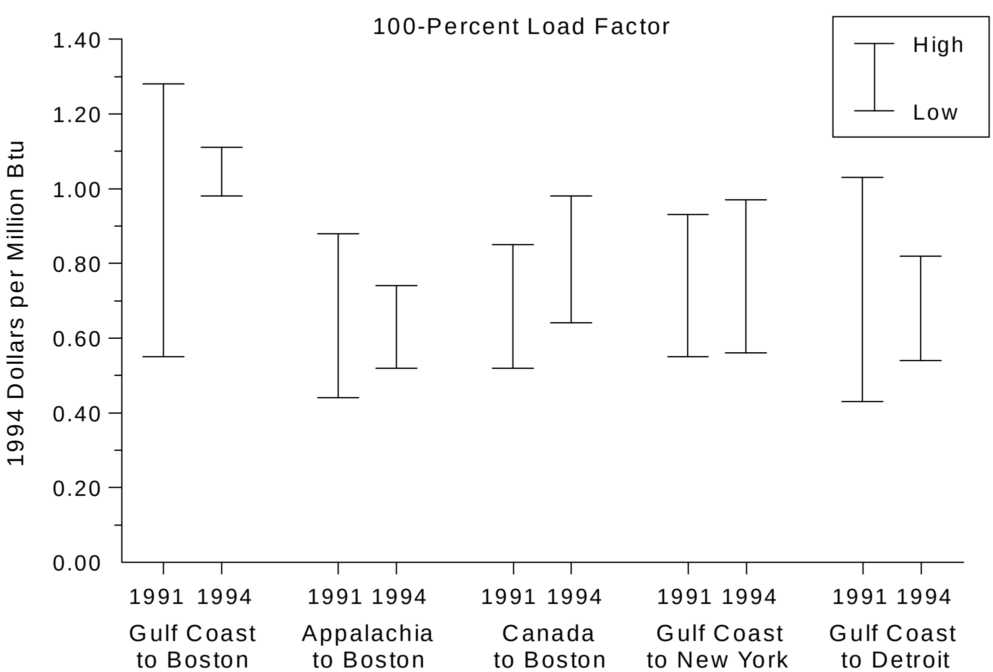
[70]There are two ways in which a release arrangement is processed. (1) A releasing shipper may make a prearranged deal with the replacement shipper if the price for the capacity is equal to the maximum firm rate in the tariff or if the duration of the contract does not exceed one calendar month. (2) If neither of these conditions are met, the releasing shipper will post the release (along with the corresponding limitations or conditions, such as recall rights and award criteria) on the pipeline company's electronic bulletin board where prospective replacement shippers bid on the capacity rights. This process results in capacity release rates that are set by the market conditions instead of a FERC ratemaking process. Currently, the maximum rate for capacity release may not exceed the maximum firm rate stated in the pipeline company's tariff.

Table 10. Range of Maximum Transportation Rates for Corridors with Multiple Routes, 1991 and 1994
(1994 Dollars per Million Btu)

Supply to Market Corridors	100-Percent Load Factor		40-Percent Load Factor	
	1991	1994	1991	1994
Gulf Coast to Boston	0.73	0.13	1.26	0.41
Appalachia to Boston	0.44	0.22	0.82	0.40
Canada to Boston	0.33	0.34	0.98	0.83
Gulf Coast to New York	0.38	0.41	0.65	1.06
Gulf Coast to Detroit	0.60	0.28	1.04	0.66

Source: Energy Information Administration, Office of Oil and Gas, derived from: **1991:** Foster Associates, *Competitive Profile of U.S. Interstate Pipeline Companies* (October 1991); **1994:** Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foster Associates, *Competitive Profile of Natural Gas Services* (December 1994).

Figure 14. Range of Maximum Transportation Rates for Corridors with Multiple Routes, 1991 and 1994



Source: Energy Information Administration, Office of Oil and Gas, derived from: **1991:** Foster Associates, *Competitive Profile of U.S. Interstate Pipeline Companies* (October 1991); **1994:** Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foster Associates, *Competitive Profile of Natural Gas Services* (December 1994).

throughout the year, resulting in more efficient use of the existing pipeline capacity. Capacity release also permits more buyers to reach more sellers by making firm transportation available to shippers who may not otherwise be able to obtain service. For example, prior to capacity release, a shipper would not be able to contract for firm transportation service on a pipeline that was fully subscribed (all capacity was contracted for). However, under capacity release the shipper may be able to use released capacity to connect to the gas supply of its choice.

The revenue generated by capacity release decreases the total cost of pipeline transportation to low-load-factor customers.[71] As discussed earlier, these customers pay reservation charges to hold space on the pipeline to meet their maximum requirement on any single day. These customers frequently underutilize this capacity, which causes their average cost of transportation to be relatively high. The revenue these customers receive for their released capacity offsets some of their transportation costs.

The capacity release market has grown steadily since its full activation on November 1, 1993. Pipeline capacity traded during the 1993-94 heating season (November 1993 through March 1994) amounted to 762 billion cubic feet. Capacity held by replacement shippers during the 1994-95 heating season was 1,570 billion cubic feet. Approximately $568 million in revenue credits from November 1993 through March 1995 were generated by the capacity release market—$528 million from released pipeline capacity and $40 million from released storage capacity. Revenues from pipeline capacity released during the 1994-95 heating season increased in all regions compared with the 1993-94 heating season (Figure 15). For the Northeast Region, the revenues in the 1994-95 heating season totaled almost $74 million, more than double the revenues generated during the 1993-94 heating season. Although the apparent growth in the capacity release market appears promising, its effectiveness at reducing the cost of firm transportation will depend on the unit price received for released capacity compared with that paid for firm transportation.

Rates for released capacity vary from region to region and tend to be significantly less than maximum firm transportation rates. Rates for capacity release transportation represent an average 64 percent discount from the maximum firm transportation rate.[72] The average price for released capacity has been fairly stable except for modest seasonal fluctuations during the winter months (Figure 16). This contrasts with the amount of capacity traded, which has increased steadily (Figure 17). The highly discounted price level may indicate that an abundance of capacity is available from releasing shippers.

The price for capacity release has a pronounced seasonal pattern in the Northeast Region (Figure 18), indicating a strong demand for capacity during winter periods. The prices for capacity release are at their highest levels during the winter season when capacity on pipeline systems is more likely to be constrained. LDC's, who comprise the bulk of the releasing shippers, must retain their capacity to supply gas to their residential and commercial heating-load customers. During the summer months, when pipeline capacity may be underutilized, released capacity is abundant and returns a much lower price. Alternatively, a consistent high average price for released capacity may suggest a consistent strong demand for the capacity. This may be the case in the Southeast Region where the 1994 average price for released capacity was more than three times the national average price (Table 11). The Southeast Region has an expanding gas market and only a few pipelines serving the area. Therefore, capacity may be constrained or there may be only limited released capacity in that region leading to the high prices for released capacity.

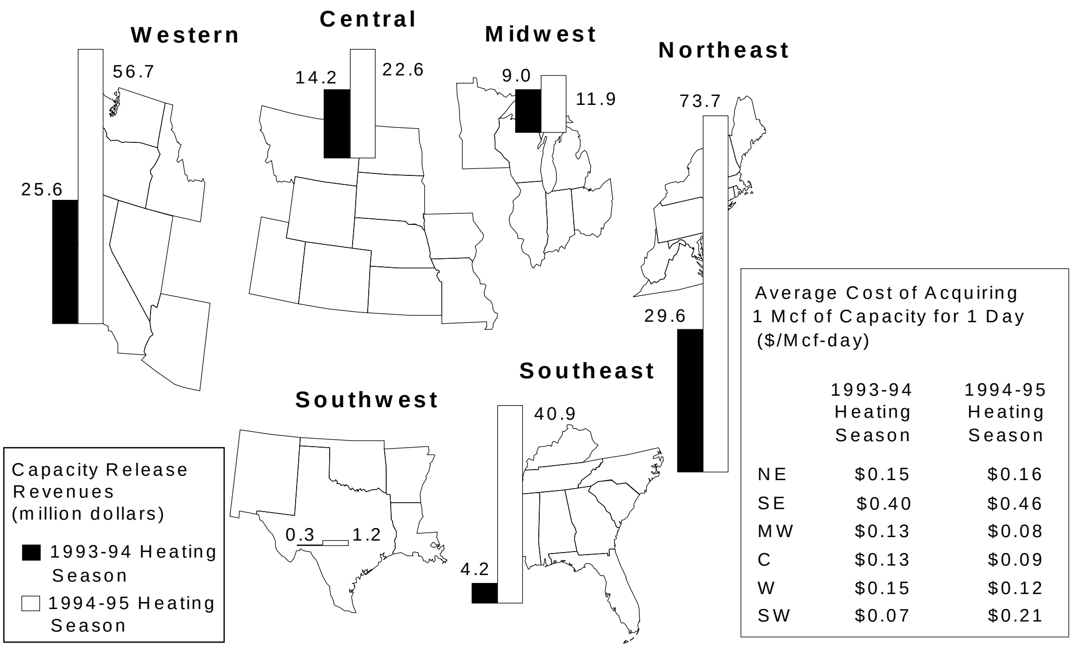
The capacity release market not only reduces the cost of reserving capacity on the system, it also gives replacement shippers a generally low cost alternative to capacity obtained directly from the pipeline company. Before this market emerged, economies of scale limited competition on a corridor to a small number of pipelines. As a result of the emergence of the secondary market, a shipper now can potentially obtain capacity from an average of almost 70 holders of capacity rights on a given pipeline.[73] The number of effective suppliers is probably substantially lower than 70 per pipeline. For example, the shippers may need some of the capacity for themselves; the delivery points of the potential releasing and acquiring shippers may not match; and the excess capacity may be upstream while the capacity desired may be downstream. Nevertheless, the creation of a secondary market in pipeline capacity represents a substantial increase in the degree of effective competition in the market for pipeline capacity. This creation of an intra-pipeline market in capacity preserves the scale economies inherent in transmission while effectively providing for a competitive and thus more efficient market in pipeline capacity.

[71]Some LDC's with very low load factors may not be able to obtain the revenue crediting benefits from released capacity. The lowest load-factor customers are generally the smallest LDC's. Since they are often served under one-part rates, they are not able to mitigate their costs through capacity release, because it only applies to customers receiving service under two-part rates.

[72]Interstate Natural Gas Association of America, *Gas Transportation Through 1994*, August, 1995.

[73]See Arthur De Vany and W. David Walls, "Natural Gas Industry Transformation, Competitive Institutions and the Role of Regulation," *Energy Policy* 1994, 22 (9) 755-763, footnote 31.

Figure 15. Heating Season Revenues from Release of Pipeline Capacity



Average Cost of Acquiring 1 Mcf of Capacity for 1 Day ($/Mcf-day)

	1993-94 Heating Season	1994-95 Heating Season
NE	$0.15	$0.16
SE	$0.40	$0.46
MW	$0.13	$0.08
C	$0.13	$0.09
W	$0.15	$0.12
SW	$0.07	$0.21

$/Mcf = Dollars per thousand cubic feet.

Notes: Revenues used in price calculation 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 inconsistent release rates. The excluded data account for about 10 percent of pipeline capacity volumes traded. Also, revenues calculated for capacity transactions with volumetric rates assume 100-percent load factor use of capacity.

Source: Energy Information Administration, Office of Oil and Gas, derived from: capacity release transaction data provided by Pasha Publications, Inc.

Currently several transportation services compete with the capacity release market. These services include traditional interruptible transportation, short-term firm transportation offered by pipeline companies, and capacity obtained through gray market transactions.[74] However, there is little doubt that the emerging capacity release market represents an important institutional innovation.

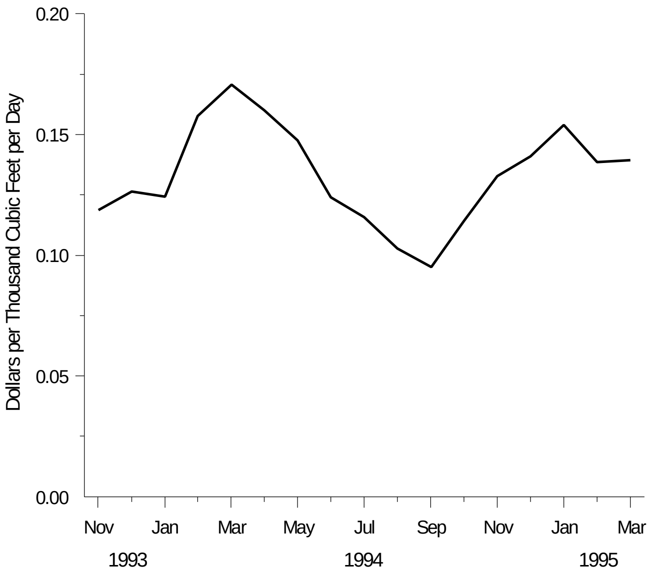
Natural Gas Prices and Markups, 1988-1994

While some transmission rates have declined as a result of changes in Federal policies, others have increased. A cursory analysis might conclude that recent policies have had a mixed effect on the cost of natural gas transmission. However, transmission rates, whether they represent maximum posted or actual transactions, do not fully reflect the impact of policy changes on the cost of moving gas from the wellhead to the citygate or to the burnertip. Recent policy has been to provide both producers and consumers of gas with more choices. Prior to the recent institutional changes, the combined merchant/shipper status of the pipeline companies resulted in consumers of gas having very limited choices with respect to both gas supply and transmission. The choices currently available to market participants have affected the cost of moving gas in ways that are simply not captured in the tariff rate associated with moving gas from point A to point B. Under the new policies, gas that previously moved from A to B may instead flow at lower overall cost from a new point, C to B.

End-use, citygate, and wellhead prices can be used to estimate transmission and distribution markups to the various end-use sectors. The transmission markup represents the cost of moving gas from the wellhead to the citygate and is calculated as the difference between the citygate price and the wellhead price. The distribution markup represents the LDC's charge for delivering the gas from the citygate to the end user and is calculated as the difference between the retail price to onsystem end users and the citygate price.

[74]Short-term firm capacity is that portion of unused firm transportation capacity on its system that a pipeline company decides to sell. The gray market is broadly viewed as transportation or storage that is bundled with gas and sold as a deregulated service by marketers and LDC shippers.

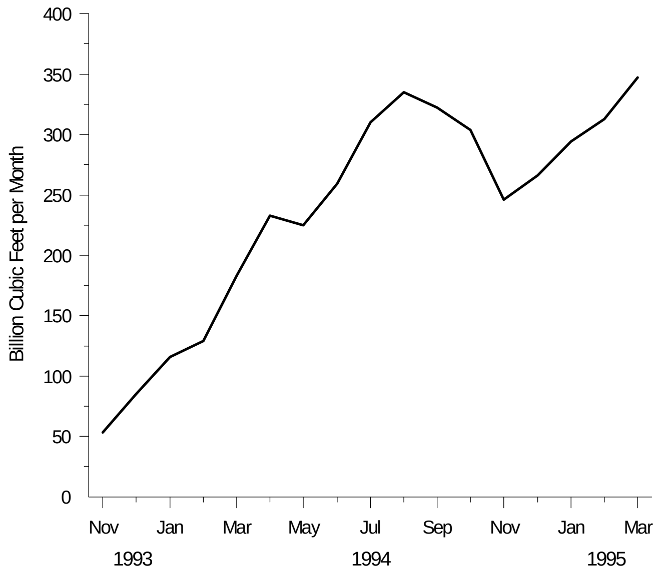
Figure 16. Average Price for Released Pipeline Capacity, November 1993 - March 1995



Notes: Revenues used in price calculation 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 inconsistent release rates. The excluded data account for about 10 percent of pipeline capacity volumes traded. Also, revenues calculated for capacity transactions with volumetric rates assume 100-percent load factor use of capacity.

Source: Energy Information Administration, Office of Oil and Gas, derived from: capacity release transaction data provided by Pasha Publications, Inc.

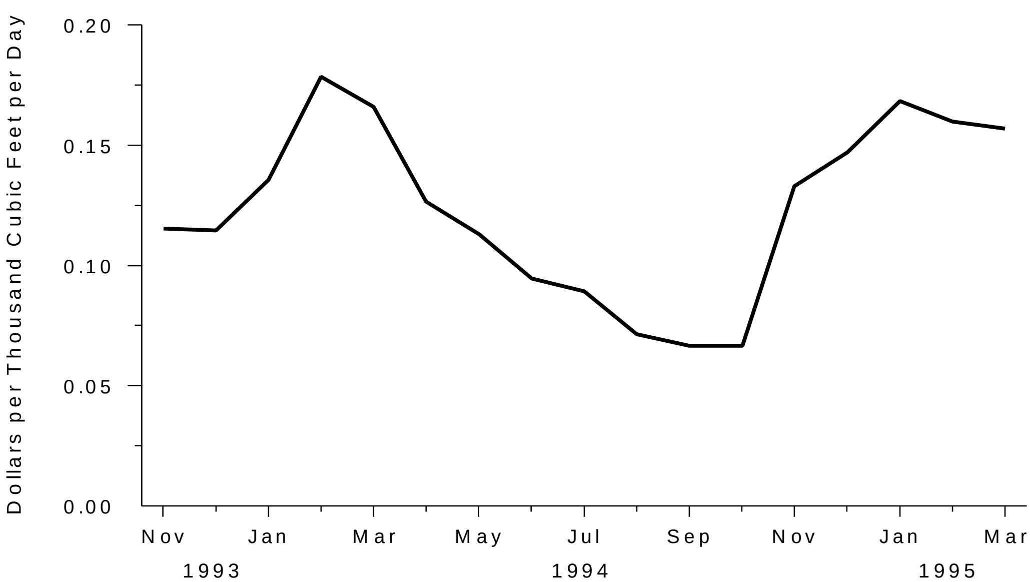
Figure 17. Pipeline Capacity Held by Replacement Shippers, November 1993 - March 1995



Notes: Excludes volumes associated with capacity release rates that are stated as a percent of effective maximum rates, capacity for transactions with incomplete data, and capacity for one transaction with an inconsistent release rate. The excluded data account for about 10 percent of pipeline capacity volumes traded. Capacity for a month is the sum of the daily capacity held by replacement shippers during the month.

Source: Energy Information Administration, Office of Oil and Gas, derived from: capacity release transaction data provided by Pasha Publications, Inc.

Figure 18. Average Price for Released Pipeline Capacity in the Northeast Region, November 1993 - March 1995



Notes: Revenues used in price calculation 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 inconsistent release rates. The excluded data account for about 10 percent of pipeline capacity volumes traded. Also, revenues calculated for capacity transactions with volumetric rates assume 100-percent load factor use of capacity.

Source: Energy Information Administration, Office of Oil and Gas, derived from: capacity release transaction data provided by Pasha Publications, Inc.

Table 11. Average Price for Released Pipeline Capacity by Region, 1994
(Dollars per Thousand Cubic Feet per Day)

Region	Price
Northeast	0.11
Southeast	0.45
Midwest	0.09
Central	0.14
Western	0.11
Southwest	0.12
U.S. Average	**0.13**

Notes: Revenues used in price calculation 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 inconsistent release rates. The excluded data account for about 10 percent of pipeline capacity volumes traded. Also, revenues calculated for capacity transactions with volumetric rates assume 100-percent load factor use of capacity.

Source: Energy Information Administration, Office of Oil and Gas, derived from: capacity release transaction data provided by Pasha Publications, Inc.

The end-use price is the average retail price paid for gas by a single customer class or sector (e.g., residential, commercial, industrial, and electric utility). It includes the costs of the many transactions necessary to bring natural gas from the producing field to the burnertip, including the citygate price and the wellhead price. Between 1988 and 1994, end-use prices for all sectors fell, with the greatest declines experienced by the onsystem industrial and electric utility sectors, 15 and 19 percent respectively. The decline in end-use prices experienced by residential and commercial customers was considerably less, only 4 and 3 percent, respectively (Table 12).

Retail gas price data for the electric utility sector are the only data that encompass both onsystem and offsystem purchases of gas by end users.[75] They show clearly the benefits of enhanced competition and open access in the transportation markets. Not only can electric utility (and industrial) consumers obtain transportation service at lower prices, they can also shop for the lowest priced gas supplies. As a result, real electric utility gas prices declined between 1988 and 1994, but experienced an upturn in both 1992 and 1993 reflecting the increase in wellhead prices in those years.

[75]Price data for electric utilities are based on reports by the utilities themselves on their total gas purchases. Retail price data for the other sectors are based on reports by pipeline companies and LDC's on their gas sales to these sectors and therefore do not include offsystem sales.

The citygate price is the average delivered price of gas to the LDC. It represents a weighted average of the delivered cost of gas across all customer classes served by LDC sales. Between 1988 and 1994, the real citygate price declined 13 percent, from $3.54 to $3.08 per thousand cubic feet (Table 12). The magnitude of the decline varies by region, with the price falling less than the average in the Northeast (9 percent) and more in the Midwest and West (19 and 18 percent, respectively).

The wellhead price is the price paid to the producer for the natural gas, in other words, the commodity cost. Between 1988 and 1994, the real natural gas wellhead price declined 11 percent, from $2.05 to $1.83 per thousand cubic feet (Figure 19 and Table 12).

Because of the different service requirements of the end-use sectors, the relative importance of each component of price varies substantially among the sectors (Figure 20).

- **For residential and commercial customers, most of the end-use price is directly related to the costs of local distribution.** For instance, the LDC markup accounted for 52 and 43 percent of the total price paid by the residential and commercial consumers, respectively. The costs of transportation services by pipeline companies accounted for 20 and 23 percent of the respective end-use prices, while the wellhead price accounted for 29 and 34 percent, respectively.[76]

- **For the onsystem industrial and electric utility sectors, the wellhead price of natural gas is the largest component of the total end-use price.** In 1994, the wellhead price accounted for 60 percent of the industrial price while the combination transmission and distribution charge accounted for the remaining 40 percent. In the electric utility sector, the wellhead price accounted for 80 percent of the 1994 end-use price while the transmission and distribution charge comprised the remaining 20 percent.

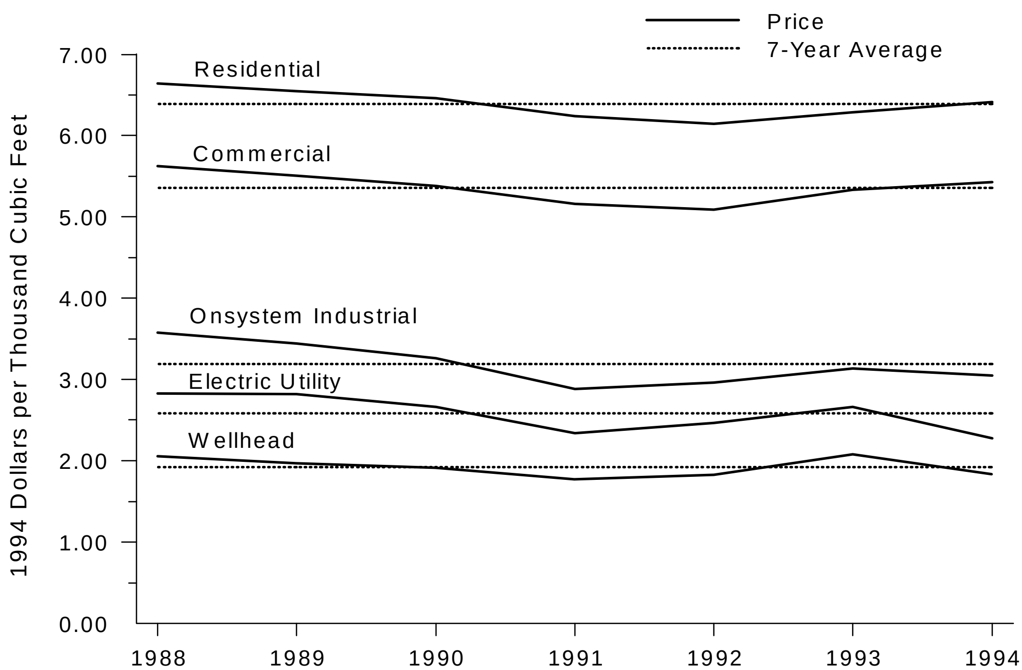
[76]The citygate price used in the calculation of these components is a weighted average of the delivered cost of gas across the customer classes served by LDC sales. Because it may include lower cost onsystem industrial and electric utility volumes, it may understate the delivered citygate price to the residential and commercial sectors. As a result, the distribution markup to residential and commercial customers may be overstated, and the transmission markup may be understated. However, this problem is relatively minor given that approximately 87 percent of deliveries to the citygate in 1994 were accounted for by deliveries to residential and commercial customers.

Table 12. Average Natural Gas Prices and Price Changes, 1988 and 1994
(1994 Dollars per Thousand Cubic Feet)

Price	1988	1994	Price Change	Percent Change
Wellhead	2.05	1.83	-0.22	-11
Citygate	3.54	3.08	-0.46	-13
End Use				
Residential	6.64	6.41	-0.23	-3
Commercial	5.62	5.43	-0.19	-3
Onsystem Industrial	3.58	3.05	-0.53	-15
Electric Utility	2.83	2.28	-0.55	-19

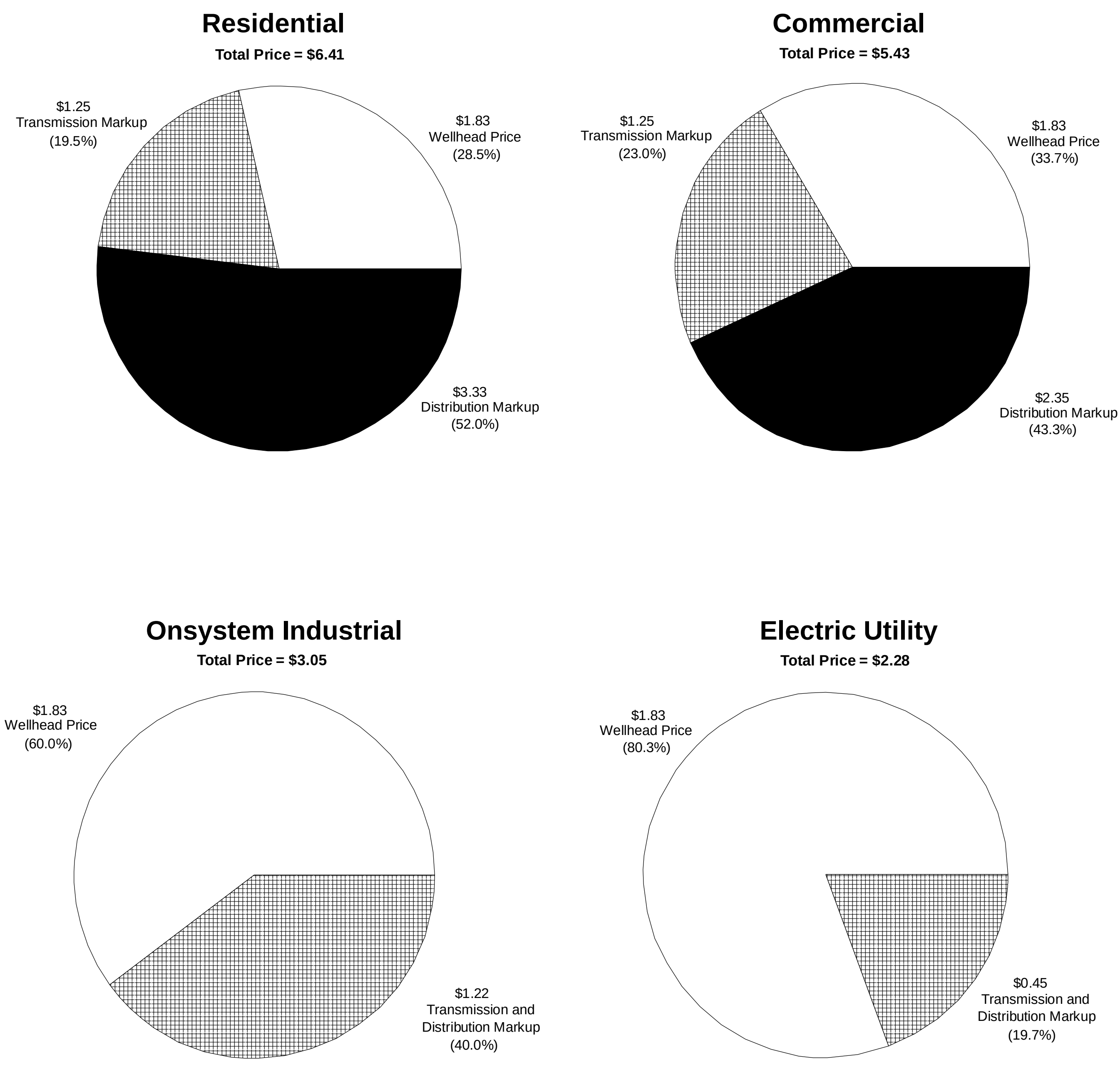
Note: Industrial end-use price data represent onsystem sales only. The onsystem share of total sales to industrial consumers declined from 43 percent in 1988 to 22 percent in 1994.
Sources: Energy Information Administration. **1988**: *Natural Gas Annual 1992*, Vol. 2 (November 1993). **1994**: *Natural Gas Monthly* (August 1995).

Figure 19. Wellhead and End-Use Prices by Sector, 1988-1994



Note: Industrial end-use price data represent onsystem sales only. The onsystem share of industrial deliveries declined from 43 percent in 1988 to 22 percent in 1994.
Sources: Energy Information Administration. **1988:** *Natural Gas Annual 1992,* Vol. 2 (November 1993). **1989-1994:** *Natural Gas Monthly* (August 1995).

Figure 20. Components of End-Use Prices by Sector, 1994
(Dollars per Thousand Cubic Feet)



Note: Industrial end-use price data represent onsystem sales only. In 1994, 22 percent of sales to industrial consumers were onsystem.
Source: Energy Information Administration, Office of Oil and Gas, derived from: *Natural Gas Monthly* (August 1995).

Before proceeding, it should be noted that as a result of data limitations, the end-use prices used to calculate the industrial and commercial transmission and distribution markups reflect only onsystem sales. As a result, the markups overstate the actual markups for these sectors (Figure 21). While this issue is a concern in the case of the commercial sector, where onsystem sales account for 78 percent of deliveries, it is an especially serious limitation in the industrial sector where the burnertip price reflects only 24 percent of the market.

Except for the commercial customers, combined transmission/distribution markups declined during the period 1988 through 1994 (Figure 22). Specifically, the markup for the industrial sector fell by 20 percent, while the electric utility markup declined by 42 percent. The declines in these markups are no doubt largely attributable to the increase in transportation options available to these customer classes during this period.

In fact, average industrial retail prices have been lower than citygate prices as LDC's have attempted to prevent their industrial customers from bypassing their system with direct tie-ins to nearby pipelines. Loss of industrial customers, with their higher and less variable demands, would increase the LDC's unit cost of service. These higher rates would have to be covered by the residential and commercial customers remaining on the system. Therefore it may be to the advantage of all of its customers for LDC's to discount prices to those customers who contribute most to lowering the overall costs of the LDC.

The combined transmission/distribution markup for the residential and commercial sectors declined marginally in the 1988 through 1993 period, but rose modestly from 1993 to 1994. For these sectors, the combined transmission/ distribution markup in 1994 was within 3 cents of the level in 1988. While the total markup paid by these customers has remained roughly constant, the transmission component of the total markup (or the markup to citygate) declined 16 percent in real terms from 1988 to 1994 (Figure 23). This is striking given that some analysts believed that the switch to straight fixed-variable from modified fixed-variable rate design would increase the average cost of transmission for these low-load-factor sectors. As discussed earlier in this chapter, a number of considerations put either upward or downward pressures on maximum tariff rates for pipeline transportation. A possible reason for the lower transmission markup to these sectors is that the higher reservation charges are being spread over a higher volume of deliveries. Also, the regulatory changes during the period may have permitted some LDC's to exploit previously unavailable lower cost transportation options.

In contrast to the transmission markup, the distribution markup for residential and commercial customers was roughly flat in real terms from 1988 through 1993, but increased substantially from 1993 to 1994 (Figure 23). The sharp increase in the distribution markup between 1993 and 1994 may reflect the higher costs incurred by LDC's who, with the unbundling of pipeline company services, have had to take responsibility for security of supply, including storage. Bypass by industrial customers and electric utilities may also have contributed to the increased LDC markups paid by residential and commercial customers in 1994.

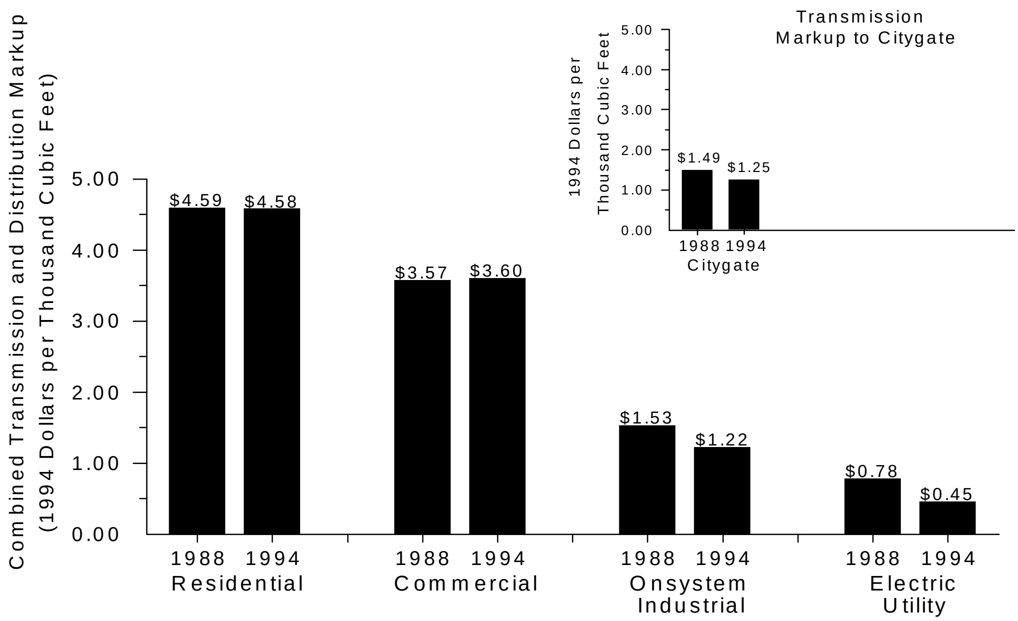
Trends in Regional Prices: End-Use and Citygate

Changes in end-use prices between 1988 and 1994 varied greatly by geographic region (Figure 24). As at the national level, the regional changes were the greatest in the onsystem industrial and electric utility sectors. In most regions, real average prices declined by 10 percent or more in these sectors (1994 dollars).

The largest regional percentage change during the period was a 29-percent drop in the real price of natural gas to electric utilities in the Western Region. In 1988, the price of gas to electric utilities in the Western Region was $3.52 per thousand cubic feet (1994 dollars), the highest of any region. Even after dropping to $2.50 per thousand cubic feet in 1994, electric utilities in this region still paid the highest average price for natural gas of all the regions. The price change from 1993 to 1994 contributed significantly to the overall drop in prices during the period. From 1993 to 1994, electric utility gas consumption increased 30 percent in this region, possibly as a result of drought conditions in the Northwest that reduced the availability of hydroelectric power. The average price of gas to electric utilities fell by $0.57 per thousand cubic feet (1994 dollars) or 19 percent from 1993 to 1994.

The largest actual price change (and second largest percentage change) also occurred in the Western Region, but in the onsystem industrial sector. The real average price of gas to industrial users fell $1.20 per thousand cubic feet (27 percent), perhaps because of competition from Canadian imports. The 1988 price of $4.45 per thousand cubic feet (1994 dollars) was the third highest in the onsystem industrial sector, and by 1994, the Western Region had only the fourth highest industrial gas prices. The average real price to industrial users fell by 10 to 16 percent in all other regions during the period.

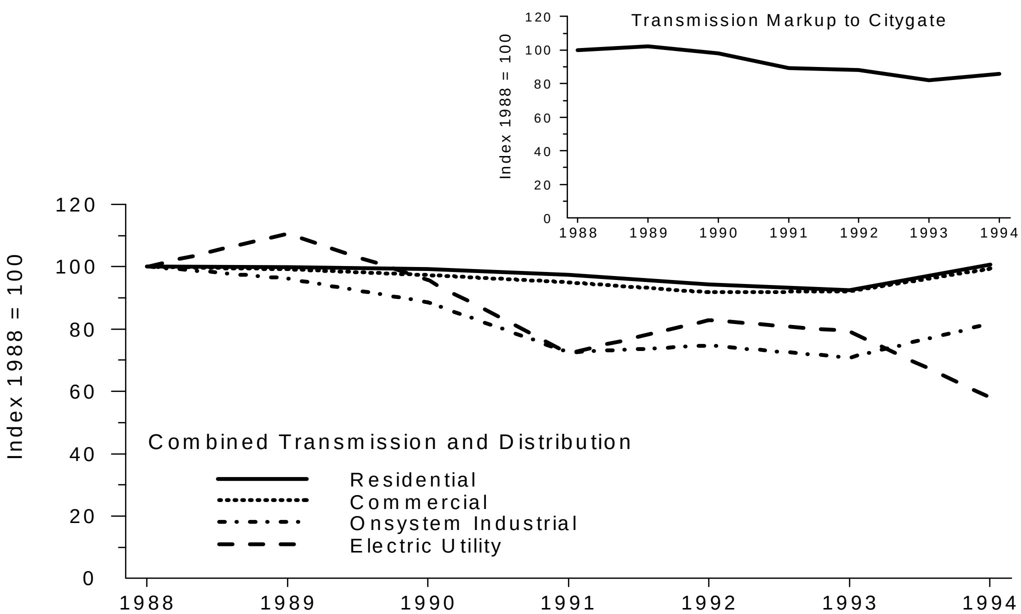
Figure 21. Transmission/Distribution Markups by Sector, 1988 and 1994



Notes: Industrial markups reflect end-use prices for onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

Source: Energy Information Administration, Office of Oil and Gas, derived from: **1988:** *Natural Gas Annual, Vol. 2* (November 1993); **1994:** *Natural Gas Monthly* (August 1995).

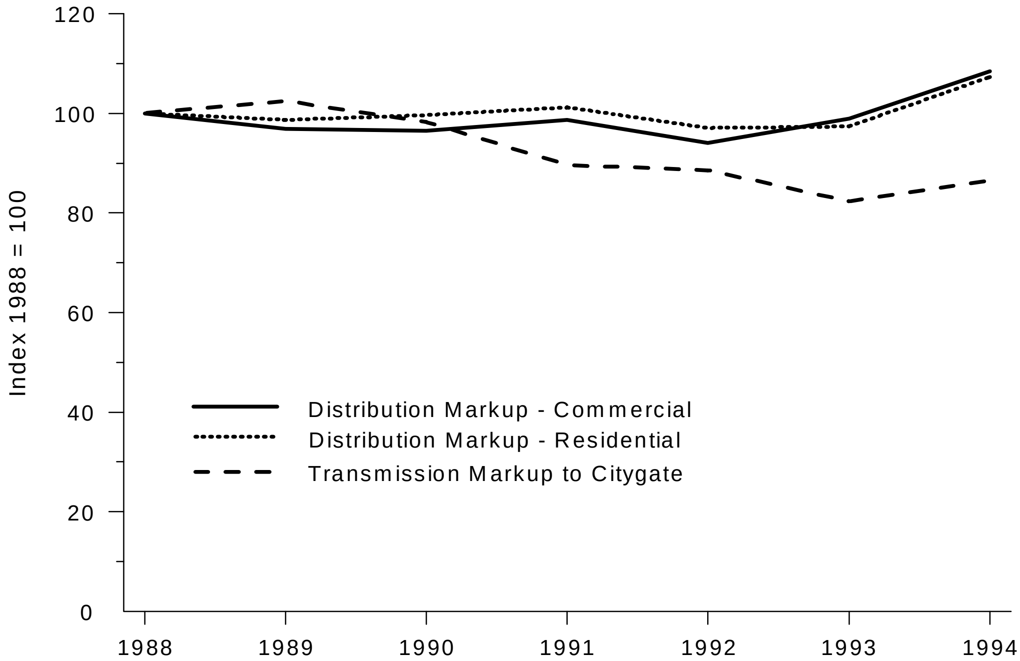
Figure 22. Indices of Transmission/Distribution Markups by Sector, 1988-1994



Notes: Industrial markups reflect end-use prices for onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

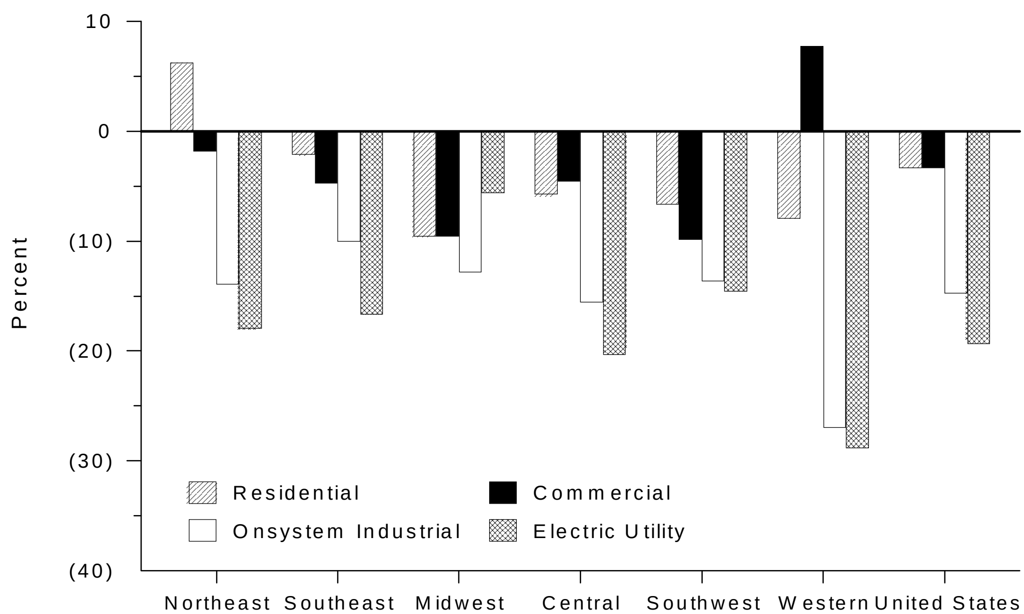
Source: Energy Information Administration, Office of Oil and Gas, derived from: **1988:** *Natural Gas Annual, Vol. 2* (November 1993); **1989-1994:** *Natural Gas Monthly* (August 1995).

Figure 23. Indices of Residential and Commercial Distribution Markups and Citygate Transmission Markup, 1988-1994



Source: Energy Information Administration, Office of Oil and Gas, derived from: **1988:** *Natural Gas Annual, Vol. 2* (November 1993); **1989-1994:** *Natural Gas Monthly* (August 1995).

Figure 24. Percentage Change in End-Use Prices by Sector and Region Between 1988 and 1994



Notes: Changes were calculated in 1994 dollars. Industrial end-use price data represent onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

Source: Energy Information Administration, Office of Oil and Gas, derived from: *Natural Gas Monthly* (August 1995).

The price changes were not as dramatic for residential and commercial users, but average real prices in these sectors did fall from 2 to 10 percent in every region, with two exceptions—residential prices in the Northeast and commercial prices in the Western Region. The price of natural gas to residential users rose $0.47 per thousand cubic feet (6 percent) in real terms in the Northeast Region. Residential gas prices in the Northeast were higher than in any other region throughout the period and reached $8.06 per thousand cubic feet in 1994. The largest decline in real residential prices occurred in the Midwest where real prices fell from $6.15 per thousand cubic feet in 1988 to $5.56 in 1994 (10 percent).

In the commercial sector, the largest real price drop also occurred in the Midwest. Commercial prices fell from $5.51 to $4.98 per thousand cubic feet during the period (10 percent) in this region. While the prices in most other regions fell from 2 to 10 percent, prices rose $0.44 per thousand cubic feet, or 8 percent, to commercial users in the Western Region. This increase moved the Western Region from the third to the second highest priced region for commercial gas users between 1988 and 1994.

Between 1988 and 1994, citygate prices, the average delivered price of gas to the local distribution company, decreased $0.46 per thousand cubic feet, or 13 percent. Although the average citygate price may not broadly apply to any specific customer sector, it may indicate the regional cost to customers. Comparing 1994 and 1988 citygate prices across the regions, the price decrease ranged from $0.26 per thousand cubic feet (8 percent) in the Central Region to $0.72 per thousand cubic feet (19 percent) in the Midwest (Figure 25). For all but two regions (Northeast and Central), the decrease in the citygate price exceeded $0.50 per thousand cubic feet, representing at least a 15-percent reduction since 1988. The smaller reduction in the Northeast probably reflects the costs associated with incremental pipeline capacity added between 1988 and 1994 as well as the great distance between this region and the major supply areas of both the United States and Canada. For each region, the decrease in citygate prices exceeded the average decrease in the wellhead price ($0.22 per thousand cubic feet). This points to an overall reduction in the costs for interstate transmission. The relatively sharper declines in the Southeast ($0.56 per thousand cubic feet), Midwest ($0.72 per thousand cubic feet), and Southwest ($0.62 per thousand cubic feet) may suggest that local distribution companies in these regions derive more direct benefits from reduced transportation costs.

Conclusion

FERC Order 636, issued in 1992 and implemented in November 1993, probably had the most significant direct effect on transportation rates between 1988 and 1994. Specifically, Order 636 separated the pipeline's merchant/ shipper role; unbundled transportation, storage, and ancillary services; changed the method of computing transportation rates; and initiated a capacity release program that allows customers to reassign their capacity rights for a revenue credit. The costs to pipeline companies of complying with Order 636 and restructuring their operations (transition costs) have also affected rates. As of August 1995, $2.7 billion in transition costs, for eventual recovery from pipeline customers, had been filed at FERC.

Prior to FERC Order 636, Order 436 (issued in 1985) initiated industry restructuring by encouraging pipeline companies to offer open access. Open access promoted producer competition, exerting downward pressure on wellhead prices. Other legislation and policies, such as the Clean Air Act Amendments, have indirectly affected transportation rates by expanding gas markets and/or encouraging conservation, Also, rates paid between 1991 and 1994 were strongly influenced by greater efficiency in operations, the cost of capacity additions, and take-or-pay costs incurred by pipeline companies.

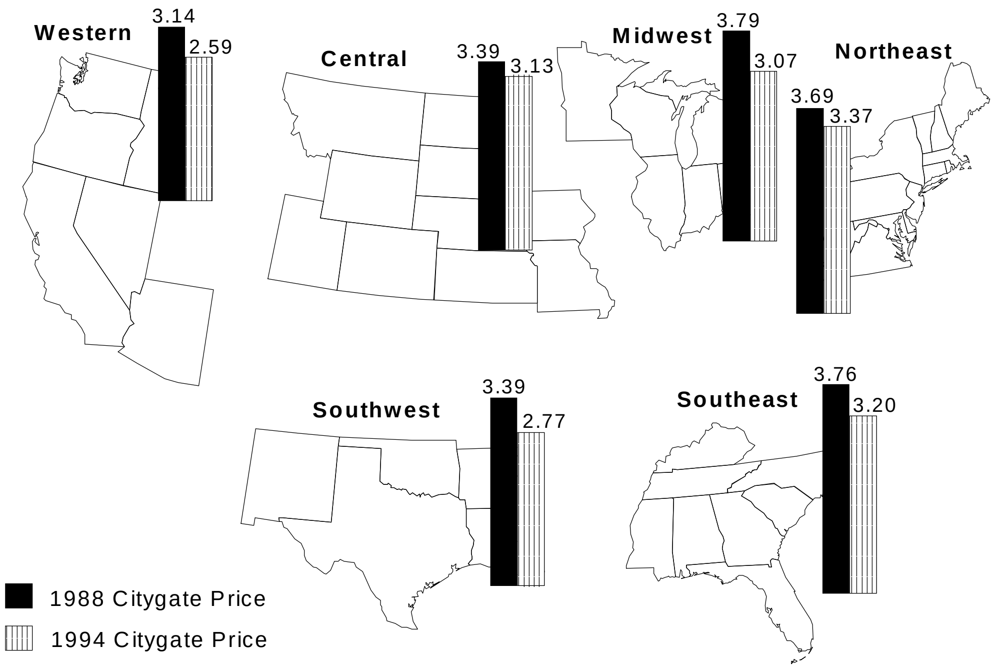
Additional conclusions are:

- On average, customers are paying less (in real terms) for natural gas service in 1994, compared with 1988. This includes declines of 11 and 13 percent in the wellhead and citygate prices, respectively, and an average decline of between of 3 and 19 percent in end-user prices. Residential and commercial prices generally declined the least, while electric utility prices declined the most. Onsystem industrial prices declined almost 15 percent between 1988 and 1994.

- Between 1988 and 1994, total transmission and distribution markups to the residential and commercial sectors remained fairly constant in real terms, while comparable prices to the onsystem industrial and electric utility sectors declined dramatically by 20 and 42 percent, respectively.

- Transmission costs, the cost of moving gas from the wellhead to the local distributor, decreased 16 percent in real terms between 1988 and 1994. However, the decrease in the transmission component was almost completely offset by an average real price increase of 7 and 13 percent in the local distribution company markup for the residential and commercial sectors, respectively.

Figure 25. Citygate Prices by Region, 1988 and 1994
(1994 Dollars per Thousand Cubic Feet)



Source: Energy Information Administration (EIA), Office of Oil and Gas, derived from: a special extract from Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers."

Although total transmission and distribution markups to captive residential and commercial consumers have remained fairly constant in real terms, they may be benefiting from the increased competition in interstate transportation.

- The analysis of maximum allowable rates suggests that low-load-factor customers have benefited less than high-load-factor customers from the recent regulatory changes. Although both categories saw both increases and decreases in tariffs, in all cases the change was more advantageous to the high-load-factor customers.

- While other influences may have mitigated SFV's downward pressure on high-load-factor rates and upward pressure on low-load-factor rates, the change in rate design was the dominant influence in widening the gap between the rates paid by the two groups. Except for the change in rate design, other key determinants of firm rates would tend to have the same general impact on customers regardless of their load factors.

- Comparing pre- and post-Order 636 rates in the corridors served by multiple pipelines suggests that transportation services offered by different pipeline companies may have been more comparable over the period. The variation among pipelines in a corridor is decreasing—with the decrease being more pronounced for low-load-factor customers. The comparison shows some convergence of rates between 1991 and 1994 for several of the corridors. One possible explanation is that increased competition and integration of the pipeline grid may have increased the comparability of services offered by pipeline companies. In addition, Order 636's directive to use a common rate design method for all pipeline companies may have led to more similarity in the rates offered by pipeline companies serving the same corridor.

- Total revenues generated by the capacity release program from November 1993 through March 1995 totaled $568 million. Trading of capacity has increased significantly since the program began and currently represents 13 percent of the overall volumes moved to market. On average, capacity trades at a 64-percent discount from maximum rates.

- The regional rates for released firm capacity vary significantly. Rates in the Southeast are higher than those in other regions possibly because of capacity constraints or the relative unavailability of released capacity in the region.

5. Information Sources

In October 1993, the Energy Information Administration (EIA) published *Energy Policy Act Transportation Rate Study: Availability of Data and Studies* to fulfill the initial requirements of Section 1340 of the Energy Policy Act of 1992. That document summarized a number of available sources of information that might illuminate the impact of Federal policies on natural gas transportation patterns and rates. This chapter follows on the earlier EIA study by discussing changes in the availability of data, information, and analyses on natural gas transportation patterns and rates. The chapter first reviews publicly available information collected by Government agencies. Next, the chapter summarizes initiatives undertaken by industry-sponsored groups and private firms.

Perhaps the most striking advance in this area is the rapid improvement in electronic dissemination of information. In fact, this chapter focuses on how electronic communications are opening up access to data and widening opportunities for analyses. In both the public and private sectors, automated data access, bulletin boards, instantaneous communications, and electronic transactions are becoming the common medium. These changes not only broaden the availability and use of information but also reduce the cost of obtaining and updating it. This, in turn, may further improve market fluidity. However, despite improvements in recordkeeping and dissemination, no additional information is available on the cost of transmission. Data on the prices paid, as opposed to the maximum and minimum lawful tariff rates, are still not available.

Government Data Resources

FERC Electronic Bulletin Boards

FERC has installed bulletin boards that provide access to the FERC data that are maintained in electronic form. These bulletin boards display announcements on file access, hold software for filing and using reported data, and provide technical instructions for using the software and the data systems.

Commission Issuance Posting System (CIPS)

CIPS is an electronic bulletin board service that provides access to the texts of formal documents issued by FERC. It includes the full text of daily issuances, news releases, Commission agendas, a list of daily filings, a list of documents issued, and letter orders. This information remains available on the system for 30 days after it is posted. CIPS is available to everyone without charge and can be accessed using a personal computer with a modem.

FERC Gas Pipeline Data System (GPD)

In June 1995, FERC made a new electronic bulletin board available to users desiring information on jurisdictional companies' gas pipeline transportation and storage activities. This system provides free electronic access to interstate pipelines' tariffs, to regulatory reports and to interstate underground storage reports. It also provides access to environmental guidelines imposed on individual pipelines. The tariff data are expected to be updated as necessary. Software and information that users can download from FERC's Gas Pipeline Data System (GPD) to their own computer systems include the following:

- FERC Automated System for Tariff Retrieval (FASTR)
- Form 2, "Annual Report for Major Natural Gas Companies"—Data for one calendar year (including Lotus spreadsheets for selected pages) filed annually
- FERC Form 2-A, "Annual Report for Non-Major Natural Gas Companies"—Data for one calendar year filed annually
- FERC Form 11, "Natural Gas Pipeline Company Monthly Statement"—Monthly data filed quarterly.

In addition, FERC will periodically post information on natural gas pipelines of general interest under heading "Miscellaneous Files" on the GPD.

FERC Automated System for Tariff Retrieval (FASTR). The most comprehensive source of information regarding interstate pipeline company services, rates and related information is the pipeline company tariff. FERC requires each natural gas company over which it has jurisdiction to file a tariff in book form and on electronic media. FERC regulations prescribe that a company's tariff "...must contain, in the order named, sections setting forth a table of contents, a preliminary statement, a map of the system, the rate schedules, general terms and conditions, service agreement forms, and an index of purchasers."[77] All general tariff items are in Volume 1 of a company's tariff. Rate schedules to cover particular services or special situations not covered under the general tariff are filed separately in Volumes 2 and 3. In many instances the actual contract for the service is filed.

FERC has developed and maintains a computer-based software and data system that contains most of a jurisdictional natural gas company's tariff filing. These are accessed using FERC's Gas Pipeline Data system. The software is known as "FERC Automated System for Tariff Retrieval," more familiarly known by its acronym "FASTR." The database contains Volume 1 information, with the exception of the system map, for some 108 jurisdictional natural gas companies (as of this writing); it also contains some information from Volumes 2 and 3 for selected companies. Appendix F includes a list of the companies currently available in the database. FERC's regulations require jurisdictional companies that, beginning on October 31, 1989, either (1) make any change to a tariff, or (2) submit a general rate proceeding pursuant to section 4 of the Natural Gas Act, to file Volume 1 information from their tariffs in an "electronic medium." To date, nearly all jurisdictional companies that file general rate tariffs are available. A few jurisdictional companies are not currently included; these are companies that have not made tariff changes or filed rate cases since October 31, 1989, and a few that received waivers.[78] The FERC system contains no information from nonjurisdictional companies, such as intrastate pipeline companies or local distribution companies (LDC's).

Volume 1 is the center of a company's tariff filing. For an interstate pipeline company, for example, it contains the rate schedules for "open-access" transportation service provided under its blanket certificate for service, together with general terms and conditions for such service, rate schedule explanatory material, sample service agreement forms, and an Index of Purchasers. For example, if a pipeline company imposed separate charges for the use of individual segments of its system (zoned rates), these would be specified in its rate schedule. As mentioned above, Volumes 2 and 3 contain tariff information of a more specialized nature. To date, electronic filing of Volume 2 and/or 3 has been voluntary.

At present, the FASTR system provides the user with the ability to view the pages of a tariff filing on a computer screen. Thus, for example, one could retrieve the entire filing for a given company and "page" through it, just as one could do with the hard-copy filing. In addition, the FASTR system allows the user to select desired parts of one or more companies' filings by using one or more user-defined criteria (e.g., only effective rate schedules, all service agreement forms, etc.). Using the FASTR system, any sheet, section (e.g., table of contents, preliminary statement, general terms and conditions, etc.), or the entire tariff filing can be displayed on screen, printed, or written to a separate computer file. Further, the user can do simple or complex word searches, write the text and/or "header records" of selected tariff sheets to separate files, display the docket numbers associated with selected tariff sheets, and others.

Currently on the FASTR system, only active records are available to be downloaded by a user. No electronic rate data are available before October 31, 1989. The date of the earliest effective rate schedules available in the tariff database will vary by company, and could be virtually any date from October 31, 1989, to the present. As of this date, archive records are available only on-site at FERC; prospective users can copy these records to an electronic medium. FERC is in the process of compiling archive records into one database and plans to have this database available before the end of 1995. Eventually, FERC plans to store archive records in separate files corresponding to the year of disposition of the records.

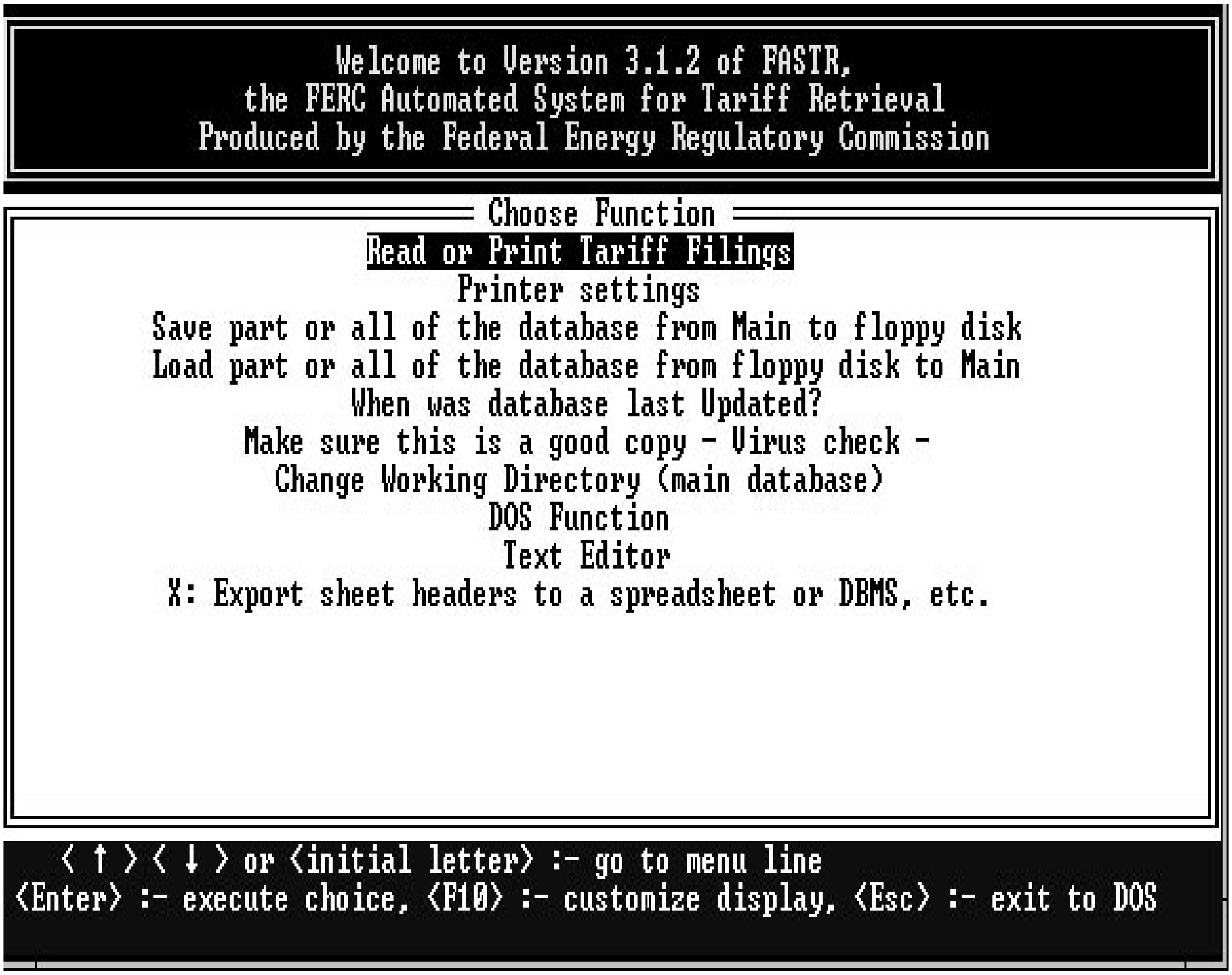
The FASTR system is a PC-based, menu-driven system. Figure 26 shows the Main Menu. The first item: "Read or Print Tariff Filings" presents a directory or listing, sorted by company name, of all tariff volumes available in the tariff database. After making a selection of the company(ies) and tariff volume(s) to retrieve, the user "tells" the system whether to retrieve the entire tariff filing or a subset. Subsequent menus lead a user through the functions available in the system.

Figures 27 and 28 are randomly drawn excerpts from two companies' tariffs that were accessed, selected, and printed using FASTR. Figure 27 is a sample table of contents of the tariff of a particular pipeline company. Figure 28 is a sample of a currently effective rate schedule for a particular pipeline company. These figures are illustrative of the output that is available from the FASTR system.

[77]Federal Energy Regulatory Commission, 18 CFR Part 154. On September 28, 1995, FERC issued a new set of instructions and standards for filing rate schedules and tariffs, Order No. 582. Changes reflecting these newly issued instructions are discussed at the end of this section.

[78]In order to receive a waiver of the filing, a pipeline company must show that it cannot reasonably file electronically. Only a few companies have requested these waivers.

Figure 26. Main Menu from FERC FASTR System



Source: Federal Energy Regulatory Commission (FERC).

Figure 27. Sample Page from the "Table of Contents" Section from the Tariff of an Interstate Pipeline Company, as Displayed by the FASTR System

TABLE OF CONTENTS
THIRD REVISED VOLUME NO. 1

		Sheet
Preliminary Statement		3
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General Terms and Conditions		
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4.	Quality	87
5.	Procedures for Requesting Service	91
6.	Facilities	107
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8.	Nominations, Scheduling and Curtailment	118
9.	System Management	135
10.	Transportation Balancing	144
11.	Possession of Gas and Responsibility	156
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17.	Interruptible Revenue Crediting Mechanism	212
18.	Miscellaneous Revenue Flowthrough Adjustment	219

FASTR = FERC Automated System for Tariff Retrieval.
Source: Federal Energy Regulatory Commission (FERC).

Figure 28. Sample Sheet from the Tariff of an Interstate Pipeline Company, as Displayed by the FASTR System

Questar Pipeline Company
FERC Gas Tariff
First Revised Volume No. 1

SUBSTITUTE FOURTH REVISED SHEET No. 5
Superseding
SUBSTITUTE THIRD REVISED SHEET No. 5

STATEMENT OF RATES

Rate Schedule/ Type of Charge (a)	Base Tariff Rate (b)	GRI Surcharge 1/ (c)	Annual Charge Adjustment 2/ (d)	Currently Effective Rate (e)
TRANSPORTATION				
	$	$	$	$
Firm Transportation - T-1				
Monthly Reservation Charge				
High-load-factor customers				
Maximum	4.99089	0.21800	-	5.20889/Dth
Minimum	0.00000	0.00000	-	0.00000/Dth
Low-load-factor customers				
Maximum	4.99089	0.13400	-	5.12489/Dth
Minumum	0.00000	0.00000	-	0.00000/Dth
Usage Charge				
Maximum	0.00292	0.00850	0.00226	0.01368/Dth
Minimum	0.00292	0.00000	0.00226	0.00518/Dth
Authorized Overrun Charge 3/				
Maximum	0.16700	0.00850	0.00226	0.17776/Dth
Minimum	0.00292	0.00000	0.00226	0.00518/Dth
Unauthorized Overrun Charge	10.00000 4/	-	-	10.00000/Dth
No-Notice Transportation - NNT				
Monthly Reservation Charge				
Maximum	0.46305	-	-	0.46305/Dth
Minimum	0.00000	-	-	0.00000/Dth
Interruptible Transportation - T-2				
Usage Charge				
Maximum	0.16700	0.00850	0.00226	0.17776/Dth
Minimum	0.00292	0.00000	0.00226	0.00518/Dth
Unauthorized Overrun Charge	10.00000 4/	-	-	10.00000/Dth
FUEL REIMBURSEMENT - 1.5% in-kind for Rate Schedules T-1 and T-2.				
OPTIONAL VOLUMETRIC RELEASES 5/				
Firm Transportation - T-1				
Maximum	0.16408	0.00717	-	0.17125/Dth
Minimum	0.00000	0.00000	-	0.00000/Dth
Pipeline Usage Charges Applicable to Volumetric Releases 6/				
Maximum	0.00292	0.00850	0.00226	0.01368/Dth
Minimum	0.00292	0.00000	0.00226	0.00518/Dth

OTHER CHARGES:
Marketing Fee: - As negotiated between Questar and shipper when Questar actively markets shipper's released capacity.
Request for Firm Service Charge: According to § 5 of the General Terms and Conditions.
Imbalance Charge: According to § 12 of the General Terms and Conditions.

Issued by: L.F. GILL, VICE PRES.
Issued on: December 8th, 1994

Effective: October 1st, 1994

FASTR = FERC Automated System for Tariff Retrieval.
Source: Federal Energy Regulatory Commission (FERC).

Because of the size of the files, the entire database cannot be downloaded in one step. Individual companies must be selected and downloaded one at a time. Downloading an average company tariff takes approximately 5 minutes; however, the user is only allowed 60 minutes of consecutive log-on time and 6 hours total time in any given day. Therefore, it will take several log-on sessions over a period of days to download the entire database.

Overall, the FASTR system provides quick, reliable and relatively easy access to the rate and service information contained in interstate natural gas pipeline company tariffs. However, the tariffs contain only maximum and minimum rates, and not the price charged for services in markets where discounts might be available. As the FASTR databases contain information pertaining only to jurisdictional companies, a customer must look elsewhere for rate information if he requires service from nonjurisdictional entities, such as local distribution companies. A customer cannot determine from a tariff if alternative sources of pipeline capacity are available.

On September 28, 1995, FERC issued Order 582, a new final rule governing the form and composition of interstate natural gas pipeline tariffs and the filing of rates and charges for interstate transportation of natural gas. This rule was adopted in order to conform tariffs and rate schedules to recent regulatory and structural changes in the industry.[79] The new procedures will alter, to some degree, the information on interstate pipeline companies' transportation and storage activities. The changes are intended to reflect industry and regulatory practices in the post-636 environment of unbundled transportation and storage services. The order reorganizes tariff and rate schedule filings, eliminates outmoded regulatory requirements, and streamlines FERC regulations.

Some of the new information that companies must provide are as follows:

- A summary rate sheet, showing the currently effective rates and charges under each rate schedule

- Sufficient information (e.g., all components of rates, location of currently effective rates within the tariff, description of the calculation of monthly charges for each rate component) so that a customer could duplicate the computation of a monthly bill received for services rendered, or be able to compute accurately what the charges would be for a specific set of desired services

- An explicit statement of discounting procedures and policies

- A breakdown or list of topics within the general terms and conditions section. (This will facilitate a user's efforts to identify and understand the details of a given company's rate schedules.)

- A semiannual Index of Customers for non-open-access pipeline companies (replacing the Index of Purchasers) that shows firm transportation services and contract demand for each customer for each rate schedule (information not currently required). The companion rule requires that open-access pipeline companies provide similar information on downloadable files or on their respective electronic bulletin boards.

Other changes also improve the usefulness of the electronically filed data.[80] All rates must be stated in terms of price per thermal unit (as opposed to units of volume). Header records for tariff sheets will include a citation to the pertinent FERC Order along with the FERC docket number and issue date. Companies will be required to use FERC's *Tariff Sheet Pagination Guideline* for the designation of replacement tariff sheets. Without the pagination standard, there is no way to ensure that tariff sheets appear in the proper order nor would there be a uniform sorting methodology available for use in analyzing the succession of effective tariff provisions and rate schedules. Finally, all companies that have not yet filed their tariffs electronically would have to do so by January 26, 1996.

FERC Form 2: Annual Report of Major Natural Gas Companies. FERC Form 2 collects financial and operational information from major interstate natural gas companies subject to the jurisdiction of FERC. The report is required to be filed on paper and on electronic media by April 30 following the close of the report year.[81] FERC Form 2 respondents are major natural gas companies who sold for resale, transported, or stored for a fee a combined total of more than 50 billion cubic feet of natural gas in each of the previous 3 years.[82] The

[79]FERC issued Order 581, "Revisions to Uniform System of Accounts, Forms, Statements and Reporting Requirements for Natural Gas Companies," at the same time as Order 582. These companion orders synchronize recordkeeping, filing, and reporting standards for jurisdictional interstate natural gas companies. Order 581 is discussed in the next section of this chapter.

[80]Order 582 temporarily suspends electronic filings pursuant to subpart D of FERC's regulations because some of the revisions to the electronic filing requirements have not yet been completed. FERC plans to hold a technical conference to complete electronic filing specifications in the near future. During the suspension, only paper copies of the filings under subpart D will be required.

[81]On September 28, 1995, FERC issued Order 581, which revised reporting requirements for jurisdictional natural gas companies. The primary impacts of the revisions are noted here; however, the revisions will apply only to data for 1996 and beyond.

[82]FERC Order 581 revises the definition of companies that are required to file FERC Form 2. In the future, Form 2 will be filed by each major interstate natural gas company that has transported or stored for a fee a combined total of natural gas exceeding 50 million dekatherms in each of the 3 previous calendar years.

data collected include financial and operating statistics on pipeline and storage activities. Specific data include depreciation, amortization and depletion, income statements and retained earnings, materials and supplies, salary and wage distribution, construction work in progress, operating revenues, and operation and maintenance expenses.

The data collected are used by FERC for pipeline regulatory review and ratesetting. In addition, other government agencies also use the data: DOE for policy issues, EIA for statistical purposes and publications, and State regulatory commissions to gather information for policy and regulation. FERC has revised its data collections to reflect the changes brought about by FERC Order 636, the Energy Policy Act of 1992, and industry developments. On September 28, 1995, FERC issued Order 581, "Revisions to the Uniform System of Accounts, Forms, Statements and Reporting Requirements for Natural Gas Companies." The major thrust of the revisions to Form 2 is to identify revenues from transportation of gas for others. This information is needed to understand current pipeline operations.

For example, the Form 2 schedule for reporting transportation revenues and volumes formerly applied to gas transported for others. It requested little detailed information about these transactions because they were not an important component of the pipeline companies' activities. With the unbundling of the transportation component of a pipeline company's business, this schedule now applies to almost all of the gas that moves on jurisdictional pipelines. In addition to volumes, revenues, and applicable rate schedules, the revised schedule requires revenues to be disaggregated by type (Transition Costs, Operating, Other, and Gas Research Institute (GRI) and Annual Charge Adjustment (ACA)), as well as by zone and rate schedule. Other revenues in the revised schedule include both reservation charges and usage charges. The schedule for transmission system peak deliveries has also been changed. In the revised schedule, volumes of gas transported are separated into (1) no-notice, (2) firm, and (3) interruptible. Volumes of gas withdrawn from storage are also separated by type into firm and interruptible.

Data collected in this new format have the potential to provide a more detailed picture of annual pipeline operations than is currently available. These improvements will help in the analysis of transportation operations and their financial implications in the new transportation environment. However, the Form 2 data will still have limitations—they are only available annually; they focus on the individual companies and not on markets; and they presume that pipeline regulation will continue to follow the established "cost-plus" methodology. Although the revisions to Form 2 will make more data available, additional information on variations in pipeline operations during a calendar year are not available; therefore, seasonal changes and peak-period operating constraints cannot be analyzed from the Form 2 perspective. Moreover, coverage of pipeline activities will continue to be limited to those jurisdictional companies required to file Form 2.

FERC Form 11: Natural Gas Pipeline Monthly Statement. Form 11 is designed to obtain monthly information on selected revenues, income statements, and other items. In the future, Form 11 will be filed once each quarter.[83] The form has been revised to provide data that will be consistent with the revised Form 2 annual reports. The revised form will include separate data on the quantities and revenues of third-party transportation and storage. Currently, Form 11 is filed by 52 companies.

The Federal Government has been collecting similar monthly data from major pipeline companies since December 1964. Currently, FERC collects these data monthly from natural gas companies on paper and, since 1988, in electronic form. The report must be filed by any natural gas company whose combined gas sale for resale and gas transported or stored for a fee exceeded 50 billion cubic feet in the previous calendar year.[84] Like other FERC data collections, the data are collected for regulatory and not statistical purposes; therefore, they are not treated as proprietary. Form 11 contains data on revenue, expenses, and sales along with volumetric data on purchases and production. Each month, data are collected for the prior month, the report month, and the final data for the same month in the previous year.[85] The Form 11 electronic data are filed in a uniform, standard format. This allows for easy comparison of data from one company to another.

The Form 11 data do not include transportation rates, pipeline capacity, or locations. However, future Form 11 data will allow calculation of an estimate of average transmission rates by rate schedule.

[83]Revisions to the Form 11 data collection system were included in FERC Order 581.

[84]In the future, firms reporting on Form 11 will be companies that transported or stored for a fee more than 50 million dekatherms in each of the three previous calendar years.

[85]Under Order 581, the submissions are quarterly.

Other Information Resources and Studies

Pipeline Company Electronic Information Systems

Bulletin Boards

FERC Order 636 required interstate pipeline companies to use electronic bulletin boards (EBB's) for transportation capacity release information and transactions. With the Order 636 requirement for pipeline companies to separate their sales and transportation services, it became necessary for shippers to arrange for their own transportation services. Order 636 provided shippers with a way to dispose of extra capacity by releasing capacity that would then be advertised as available to other shippers on the bulletin boards.

The first FERC-required pipeline EBB's became operational in 1993, with little standardization. Most bulletin boards were DOS-based, although three early ones were WINDOWS-based. Most pipeline companies designed individual EBB systems; a few elected to band together and have similar, though not identical ones. Each pipeline company seemed to have a different need; while some pipelines had many capacity transactions, others had few. Because FERC Order 636 did not specify what information the bulletin boards should include, the most difficult aspect of dealing with EBB's is their great variety. Accessing the EBB's is often complicated. In addition, having to use different software for each EBB raises the cost of using more than one.

The most rudimentary EBB's merely display information and, in some instances, allow users to post information. Since the initial purpose of the gas pipeline company EBB's was to facilitate the capacity release function, information on these activities was highlighted. If capacity release awards have been made, the rate paid, the routing, and the amount of capacity accepted by each replacement shipper are displayed. Some EBB's only list the dollar amount of the rate, while others also tell if this is the maximum rate allowed. If the purchase of capacity is a prearranged deal at the maximum rate or for a term of 31 days or less, it is not subject to bidding. The available routing information also varies by EBB; some list only the origin and the destination of the capacity being released. Others list every node on every route that might be used. However, all EBB's list the amount of capacity that is released.

More sophisticated EBB's have standardized file transfer capability. This allows users to download the information from the board to their own computers, work with the information, and then upload their responses back on the EBB. The EBB's of the future will go one step further and provide real-time information network connections that will permit continuous information exchange between pipeline companies and shippers.

Shortly after FERC Order 636 was issued, it became obvious that more standardization was needed. In order to address this problem, five working groups were created, consisting of members from FERC and the industry. These working groups led to the formation of the nonprofit Gas Industry Standards Board (GISB) in September 1994. The Board's mission includes developing standards for electronic information exchange and electronic communication. It was set up as a temporary organization, and an affirmative vote of its members is necessary for the GISB to continue after an initial 2-year period.

FERC and the working groups initiated actions to require standardization and to increase the electronic access to information by requiring that pipeline companies provide "downloadable" files. These downloadable files must also meet basic standards and can include more information than is required on the EBB's. In May 1994, FERC consolidated its requirements (Order 563A) for standardized EBB's and downloadable files. This order extended and standardized the content and procedures for accessing and maintaining information. The downloadable files are required to provide general information that covers issues including offers to sell firm capacity, bids for capacity, awards of capacity, withdrawal of capacity offers and bids, operationally available capacity, unsubscribed firm capacity, and customer indexes describing existing firm contracts. In November 1994, FERC ordered shippers to report information on the maximum tariff rate for transportation service, as well as the actual price paid for that service on their downloadable files.

The pipeline information contained in the downloadable files may be mandatory, optional, or conditional, but must be comparable with the information listed on a pipeline company's EBB if the pipeline maintains separate EBB and downloadable files. Individual data items must specify the service to which they apply (transportation or storage) and if they are per day, month, year, or seasonal. In addition to the offer-term, beginning and ending dates, the minimum term, and if the offer is prearranged, it must include as mandatory the following items:

- Pipeline rate schedule applicable to the offer
- Awarded quantity and rate
- Rate form (whether reservation charge only, volumetric charge only, or a blended rate)
- Indicator showing whether capacity is being released on a volumetric or thermal basis

- Gas transaction point where capacity is released
- Gas transaction point where capacity is to be delivered
- Indicator showing if the award was prearranged, permanent, or recallable.

Although GISB and FERC have made significant progress in defining the standards, protocols and contents for electronic information systems, some issues remain. FERC and GISB continue to meet and work toward a consensus on workable practices. Among the major areas still unresolved are the standards and protocols that will allow users to upload files, that is, write information back to the pipeline's computer. In September 1995, FERC held a public conference to address these issues.

Despite problems caused by the initial lack of standardization of EBB's, the number of transactions in the capacity release market has almost tripled between November 1993 and March 1995 (see Chapter 4). For example, there were 42,268 capacity release transactions during December 1994, compared with 14,781 transactions in December 1993. However, an overwhelming percentage of the awards posted on EBB's are for released capacity from prearranged deals and not from open bidding.

Integrated Systems for Information Exchange. Over time, the industry recognized that more centralized, integrated systems would be valuable. This realization led to the development of several commercial systems. Four of these integrated electronic systems have already been released. Capacity Central is a real-time electronic brokering system matching spot buyers and sellers of excess firm capacity in the less-than-30-day capacity market. This WINDOWS-based system encompassing six pipelines began trading on December 14, 1994. The other system that began trading in 1994, NrG Highway, a Canadian WINDOWS-based system, is being upgraded in 1995 to allow customers to request new contracts and modify existing ones. A U.S. pipeline company, Tenneco, will be part of NrG Highway. In 1995 two more systems are coming on line—Rapid Exchange and Channel4. Rapid Exchange is the electronic trading system of Tejas Power affiliate Prism Information, while Channel4 is the result of a joint venture by EnerSoft Corporation and the New York Mercantile Exchange.

Market Center Electronic Trading. Electronic trading is increasingly available at market centers. From a small beginning in June 1994, when Williams Energy Ventures' Streamline system for trading gas supplies went online at the Carthage hub, electronic trading has expanded to approximately 18 market centers. It allows users to buy and sell gas and capacity rights. They can (1) check price and availability of gas, (2) submit bids and offers, (3) complete legally binding transactions, and (4) prearrange capacity releases. A typical electronic trading system anonymously fills gas orders with offers, matching the highest bid with the lowest offer.

Electronic System Access. The rapid expansion of electronic information on natural gas transportation systems and markets should provide more information on certain parts of the transportation market. Data from Government sources are now more accessible than ever before. Data available from private sources, whether mandated by regulation such as the gas pipeline EBB's and downloadable files or induced by market value such as the integrated systems, are also more accessible.[86] Together, these electronic information systems can enhance well-informed markets. Moreover, these data systems allow more extensive analysis of historical data. One significant limitation of the EBB's, however, is that they capture rate information only for the traded capacity (13 percent of the market in 1994). These rates are not necessarily representative of the remaining 87 percent of the pipeline capacity market.

Other Information Sources

H. Zinder & Associates: Summary of Rate Schedules of Natural Gas Pipeline Companies

For 45 years, Zinder Companies, Inc., has been publishing *Rate Schedules of Natural Gas Pipeline Companies* (*Summary*). It was started originally as a report for their clients, i.e., pipeline companies, but now it is widely available by subscription. The format has remained nearly unchanged over the years; therefore, it can be a useful source for those familiar with the publication's long history. After approximately 6 years of being published quarterly, the *Summary* is back to being published on a semiannual basis in 1995. The data on U.S. pipeline companies are from the FERC tariff filings. The *Summary* condenses and organizes the maximum and minimum tariff data into a format that is divided into sections by pipeline company.

[86]The data on the capacity release market, for example, used in Chapter 4, were derived from information collected from pipeline companies' EBB's. Pasha Publications, Inc. collects and compiles this EBB information and publishes it.

The report organizes rate schedules into four classes—transportation, storage, sales, and suspended. The transportation and sales sections give the rates the pipeline companies charge for services, with footnotes that identify added cost elements or limitations. The storage section gives the rate for storage but it does not show the exact location of the storage. The suspended rate (major rate changes that have been filed with FERC, accepted, suspended, but are not yet effective)[87] section allows the user to factor in rate changes that may occur in the future. Every listing shows the States or regions where the natural gas company operates. As with the actual tariffs, the data in the *Summary* are not uniform because companies structure tariffs based on their own operations, with different services, measurements, rates, and formulations.

Foster Associates

In early 1995, Foster Associates published a new four-volume study on emerging competitive natural gas services, entitled *Competitive Profile of Natural Gas Services*. The study enhances and updates an earlier competitive profile of U.S. interstate pipeline companies published in the fall of 1991. The overall purpose of this multi-client-sponsored research project is to examine the current and prospective competitive profile of natural gas services. The primary goals of the study are to provide the following:

- An overview of the current and prospective U.S. market, with particular focus on market requirements, including annual, seasonal and peak-day demand levels.
- A comprehensive comparative analysis of competing service, with emphasis on transportation, storage and hub services to meet current and prospective market requirements.

The study identifies new storage facilities and the development of hubs as the most dynamic developments in today's gas markets. The services provided by these new facilities both supplement and compete with pipeline transportation. The study identifies existing storage and hub providers, as well as prospective new providers and analyzes the costs and other aspects of the services they offer.

Volume I of the report is an executive summary. Volume II contains an overview of the U.S. natural gas market plus six chapters each focusing on the competitive profile of a particular regional market: Northeast, Southeast, North Central (East), Southwest, Plains/Mountain, and Pacific. These chapters assess the characteristics and potential for natural gas growth in each region; evaluate the pipelines serving each market; review available capacity release data for each region's pipelines; identify major competitive transportation routes to selected key cities; compare current and prospective transportation rates for the different routings; and develop gas netback price comparisons based on existing and projected transportation rates less existing and projected wellhead prices. The report also includes analysis of the services and rates of independent storage companies and hub operators.

Important criteria used for comparative purposes included:

- Market characteristics, such as supply and end-use profiles and potential throughput growth
- Pipeline system configuration, including system flow and capacity
- Current and prospective transportation rates to the year 2010.

Volumes III and IV provide extensive information for 32 interstate pipeline companies entering into the competitive analysis. The corridor data used for calculations in Chapter 4 were based on information from the Foster studies.

GRI's Pipeline Cost Trends Study

The Gas Research Institute (GRI) is conducting a study in 1995 to identify pipeline cost trends and the elements affecting growth in transportation costs from the early 1980's through the early 1990's. The study relies on data filed by interstate pipelines in FERC Form 2. It will update a previous analysis of trends in the costs of gas transmission and distribution from 1971 to 1985.[88] Similar results from the 1987 study are incorporated in the calculation of transmission and distribution costs for GRI's annual baseline projections. The current study will update the trends and revenue requirement assumptions for transmission costs. It is expected to be published in late 1995.

Included in the scope of this study is an examination of the operation and maintenance costs of transmission systems; the capital costs related to depreciation of facilities; and return on investment. The analysis will focus on aggregate cost trends of gas transmission companies. The study will concentrate on cost patterns and trends for the industry as a whole. Although the circumstances and factors affecting costs vary for each pipeline, no attempt will be made to present cost trends for individual companies.

The preliminary findings of the study are as follows:

- Revenue requirements have declined between 1981 and 1992.

[87]Zinder Companies, Inc., Foreword, *Summary of Rate Schedules of Natural Gas Pipeline Companies*, 96 edition (March 15, 1995).

[88]Gas Research Institute, *Factors Affecting Growth in Gas Transportation Costs Since 1970* (November 1987).

- Restructuring costs comprise a significant portion of revenue requirements and by the late 1980's averaged about $1.4 billion annually.

- Transmission costs, excluding fuel and power, are about constant from 1981 through 1992.

- Storage costs declined from 1981 through 1992 as both fuel and power and operating costs declined.

- Both transmission and storage costs intensities (cost per unit of service) declined throughout the period, indicating improved operating efficiency industry-wide.

- Costs for operating and maintenance (O&M) of transmission compressor stations have increased in real terms, while the O&M costs associated with mains have declined.

- Compression-related storage costs have not declined.

As was the case with the earlier cost trends analyses, the updated study is a useful compilation of historic costs at the aggregate level.

GRI Order 636 Study

The Gas Research Institute (GRI) is undertaking a study of the effects of FERC Order 636 on lower 48 gas transmission and burnertip prices. Although Order 636 will significantly affect gas transmission charges, these effects do not take place in isolation. One goal of the study is to determine to what extent the prices have changed as a result of Order 636. The study will analyze whether the components of transmission, storage and gathering costs have fundamentally changed or simply been reallocated or shifted to other components of consumer prices.

The GRI study will try to separate changes attributable to Order 636 from other events that are changing gas transportation prices. The GRI study will develop an operational description of gas transmission as a matrix for gas transmission costs, identify where the cost for each component of transmission is, and display the results in the matrix. For the purpose of improving historical comparisons, the study will identify where the costs for each operation were "collected" pre-Order 636. The effects of Order 636 on actual costs will be analyzed, as well as the extent to which the effects on gas transmission costs are more general than specific, for example, where the change is limited to an individual pipeline or region. The GRI study is scheduled to be available early to mid 1996.

Conclusion

Improvements in access to data through new electronic systems, efforts to expand information systems to capture the transportation activities of pipeline companies, and the information revealed by the entry of private marketers integrating hub and transmission services all improve the availability and usefulness of information on gas markets. Some FERC efforts seem to provide promise for future analyses including the FASTR system for quick access to information on pipeline tariffs and more data on transportation and storage transactions.

Of course, even with the new accessibility and information, not all the questions about gas pipeline operations will be answered. While additional information on pipeline capacity and users is useful, data on the rates charged for pipeline services are still not available. At best, currently available data allow customers only to approximate the cost of delivering gas when making purchasing decisions. Thus, an entire segment of market information is missing. This type of price uncertainty may even reduce the efficiency of gas and transportation markets.

In addition, relying on data collected for one special purpose, such as regulation, for insight into economic behavior or patterns of market activity can be misleading. But, on balance, forthcoming improvements in data and data availability will contribute to understanding trends in gas pipeline transportation uses.

In the future, EIA will continue to review data availability in light of the needs of policy analysts and energy markets. The regular EIA cycle of data assessments and form reviews is specifically designed to address just such needs.

Appendix A

Overview of Pipeline Design and Operational Factors

Appendix A

Overview of Pipeline Design and Operational Factors

The principal requirement of the natural gas transmission system is to be capable of meeting the peak-day demand of its customers who have contracts for firm service. To meet this requirement, the principal facilities developed by the natural gas industry are a combination of transmission lines to bring the gas to the market areas and of underground storage reservoirs closer to the market areas to meet surges in demand.

Transmission System Design

The design of the transmission lines and integrated storage sites represents a series of design balances attempting to devise the most efficient and economical mix of delivery techniques given the operational requirements facing pipeline companies. These vary widely depending on the number and types of customers and access to supplies, either from production areas or underground storage. Many interstate pipeline systems are configured principally for the long-distance transmission of supplies from production regions to market areas or underground storage facilities and are characterized as "trunklines." At the other extreme are the interstate "grid" systems, which generally operate in and serve major market areas. Many of the grid systems can be categorized as regional distribution services. For the most part, they receive their supplies from major trunklines or directly from production areas and transport gas to local distribution companies and other customers in more than one State.

Underground storage is essential for efficient and reliable interstate natural gas transmission. A pipeline company avoids the need to expand transmission capacity from production areas by contracting for or establishing storage facilities. In market areas where there is a strong seasonal variation to demand, they are used as an alternative supply source, and also for load balancing and to provide other services to customers. During the nonheating season, when customers do not use the full capacity of the trunkline system, natural gas is transported and injected into storage. By the beginning of the heating season (late October to early November), storage inventory levels are generally at their annual peak. Working gas, that is, the portion of natural gas in storage sites ordinarily available for withdrawal and delivery to markets,[89] is then withdrawn during periods of peak demand. Underground storage facilities are also located in production areas. These sites are also used to store gas that may not be economically marketable at the time of production.[90]

The great majority of storage is used in the classic mode of injection in summer and withdrawal in winter. However, new storage sites and an increasing number of older sites are used increasingly for off-season and short-term needs.

The size of the transmission line depends in large part on the availability of storage. Rather than size a line to meet peak-day requirements, the line need only satisfy the difference between peak needs and maximum withdrawal from storage as it enters the market area. In off-peak periods, the line must be able to provide off-peak needs plus injection to storage. In addition, some storage sites may require that system flow be reversible and that the main transmission line in the vicinity be able to accommodate this capability. The resulting pipeline configuration, including storage, may result in a comparatively low usage level in the off-peak season and a much higher, albeit shorter term, usage level during the peak-demand season.

Often new systems are initially designed to handle volumes beyond the minimum requirement. A number of factors are involved in calculating how much gas a pipeline can carry, the most important being the diameter of the pipe and the pressure pushing the gas along the pipe.[91] Because of flow dynamics, doubling the diameter of the pipe will increase the capacity more than sixfold at approximately twice the cost. Increasing the pipe wall thickness or strength of the pipe will enable the pipe to withstand a greater pressure. The pressure pushing the gas is usually provided by mechanical compression.

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[89]In addition to working (top storage) gas, underground storage reservoirs also contain base (cushion) gas and, in the case of depleted oil and/or gas field reservoirs, native gas. Native gas is gas that remains after economic production ceases and before conversion to use as a storage site. Upon development of a storage site, and in order to develop and maintain adequate storage reservoir pressure to meet required deliverability rates for withdrawal operations, additional gas is injected, and combined with the native gas, if any.

[90]For instance, natural gas produced in association with oil production is a function of oil market decisions, which may not coincide with natural gas demand or available pipeline capacity to transport the gas to end-use markets. Another example is the storage of gas from low-pressure wells, where the gas can be injected during the off-peak season and delivered, at high pressure, to the mainline during the peak season.

[91]Standard design codes require that all pipelines passing through populated areas have their maximum operating pressures reduced for safety reasons. It became common practice to maintain nominal diameter but increase wall thickness where a line had to be derated for its surroundings, in order to keep the working pressure rating more constant along the line.

The design process itself includes the development of cost estimates for various possible combinations of pipe size, compression equipment, and interstation distances to find the combination that minimizes transportation cost given the desired flexibility and expandability goals. New trunklines are typically built with larger diameter pipe than needed initially, but only with the currently required compression capacity. Compression can then be added, either in existing or new, intermediate stations, to increase capacity as growth in load occurs.

Customer Requirements

It is ultimately the customer requirements that determine the design capacity of pipeline system facilities. Pipeline companies seek to obtain a mix of customers and contract types in order to maximize system throughput. Firm customer requirements, generally written into long-term transportation agreements, may be expressed as a reservation on system capacity for the receipt and delivery of a maximum daily quantity of gas at specific points along the network. The pipeline company agrees to reserve capacity to provide a customer, such as a local distribution company (LDC), industrial user, or electric utility, with a firm quantity on any given day. Pipeline companies must stand ready to provide up to the contracted-for capacity under firm contracts even though their customers may not actually transport or request transport of that gas.

LDC's are the principal providers of supply to end users. They typically contract with pipeline companies for a variety of services, including transportation, and storage. They contract for firm service to meet the requirements of their high- priority customers and for interruptible service to meet the needs of their lower priority customers.

Some electric utility and industrial customers contract for service on an interruptible basis. Under interruptible contracts, deliveries are subject to curtailments by the pipeline company or local distribution company when necessary to meet the requirements for delivery under firm contracts. Rates for interruptible service are generally less expensive than for firm service. Transportation for interruptible customers is extremely important to the pipeline companies in their efforts to maintain a high pipeline throughput.

The demand for natural gas is quite diverse regionally. For example, in the northern regions of the country where a high proportion of residential and commercial customers use natural gas for heating, deliveries under firm service contracts are highly seasonal because of the extreme weather variation. Other more temperate regions, such as the Southwest, may be very dependent on natural gas used in the generation of electricity to meet summer cooling loads. The use of natural gas for industrial purposes also varies substantially from region to region. Some applications use natural gas for feedstocks and require a secure, dedicated supply of natural gas. Other uses are for boiler fuel where the user typically has the capability to burn other fuels in the event that natural gas is not available or is less economic than the alternatives.

Pipeline Utilization

Pipeline companies prefer to operate as close to capacity as possible, thus maximizing revenue; however, the average utilization usually does not reach 100 percent. Average utilization rates below 100 percent may not indicate that any unused capacity is available in practice. A pipeline company with a highly seasonal load may have a relatively low average utilization rate even if there is no unreserved capacity on its system. Yet because of the difficulty in balancing unused commitments for firm and interruptible transportation, it may be unable to provide further interruptible service to comple-ment the high level of deliveries required during the peak-consumption periods. Integration of storage capacity into the pipeline network design can increase average-day utilization rates. Storage used for seasonal demand swings effectively moves demand from one season of the year to another.

Trunklines, which are generally upstream of the market storage areas, can be designed for a more constant load than the pipelines on the downstream side of the storage fields. Storage is usually integrated into or available to the system at the production and/or the market end as a means of balancing flow levels throughout the year. Therefore, trunklines serving markets with significant storage capacity have a much greater potential for obtaining a high utilization rate because the load moving on these pipelines can be levelized. Furthermore, to the extent these pipelines serve multiple markets, they can also achieve higher utilization rates because of load diversity across the markets they serve.

Utilization on the grid systems operating closer to the market areas and downstream of the storage fields is more likely to reflect the seasonal load profile of the market being served than utilization on upstream trunklines. The grid-type systems usually operate at average utilization levels well below that of the trunklines, although during peak periods, usage levels are generally also at much higher rates. Storage services are usually highly integrated into the grid network to meet varying local market demands. Because grid systems have numerous interconnections within the network, their overall usage levels depend upon what happens in the various parts of the system. Pipeline segments that show a high degree of utilization are either serving a customer (or group of customers) with a very flat load profile, or have a significant interruptible market.

Grid systems usually show a marked variation between high- and low-flow levels, which reflects their seasonal and local market characteristics. In contrast, trunklines show less of a spread between the two as load tends to be fairly constant because of the load management designed into the system.

The primary measure of pipeline utilization used in this analysis is an estimate of average-day natural gas throughput relative to estimates of system capacity at State and regional boundaries. Another measure used is system-wide pipeline flow rates, which highlight variations in monthly system usage relative to an estimated system peak throughput level (see below, "Synopsis of Utilization Measures"). Although useful, peak-day utilization rates are not used in this report because of the limited availability of peak-day consumption data, that is, coincidental and noncoincidental peak-day flows.[92] Furthermore, these data do not necessarily measure the ultimate potential of any pipeline system, because it may be physically possible to increase flow beyond the observed levels. Also, the sum of noncoincidental peak-day flows may be greater than the total actual capacity of the system if peak demand in one location can only be supplied if lesser volumes are being delivered elsewhere. Thus, while important, this report does not address this aspect of system utilization.

Capacity Expansion

Although pipeline systems have some flexibility to handle changes in demand, sometimes system expansion and new pipeline routes are needed. There was substantial interest in expansion of the pipeline system during the late 1980's. One of the largest proposals was the Iroquois project built to bring Canadian natural gas into the Northeast through the new Iroquois pipeline. This new line began service in December 1991. Other new systems are planned or under construction that will bring additional supplies from Canada, as well as from the Rocky Mountains area and the Southwest, to the west coast.

In most cases, interstate pipeline companies are required under Section 7(c) of the Natural Gas Act of 1938 to obtain a certificate of public convenience and necessity before constructing pipeline facilities. Besides review of operational aspects of the system, other legislation requires extensive review of the environmental aspects of the projects.[93] These requirements have resulted in a very time-consuming, complex, and sometimes controversial process.

Once a project is approved and constructed under a Section 7(c) certificate, the costs of the facilities are eligible for inclusion in the pipeline company rate base (when the company files its next general rate case) and the risks associated with recovery of those costs are minimized.[94] Other options are also available to pipeline companies for capacity expansion, depending on the size of the projec and the amount of risk the company is willing to assume. These options include:

- **Blanket Certificate.** Blanket certification can be used for relatively small projects. A blanket certificate approves a series of similar actions in one authorization. For instance, construction of small additions to a pipeline may be authorized by a blanket certificate, provided the total cost does not exceed some threshold level and other eligibility criteria are met. In recent years, FERC has been using blanket certification more frequently to authorize and facilitate both construction projects and transportation programs.

- **Optional Certificate** (formerly known as Optional Expedited Certificate). In 1985, under Order 436, FERC introduced optional certificates whereby construction could be approved without assessment of its market need or competitive proposals. In return, the pipeline company agrees to bear the majority of the risk of the project. Furthermore, the pipeline company may not decrease the projected volume of services used to design rates nor shift costs to pre-existing customers.

- **NGPA Section 311**. Section 311 of the Natural Gas Policy Act (NGPA) of 1978 allows an interstate pipeline company to sell or transport gas "on behalf of" any intrastate pipeline or local distribution company. FERC has exempted the construction of facilities used solely for Section 311 transportation from certificate requirements. Construction is subject to environmental conditions and a 30-day notice to FERC, which requires only information on the delivery point of gas from the interstate pipeline, the total and daily volumes expected to be delivered, and the rate to be charged for transportation.

[92]A coincidental peak flow is the flow on the day during a specified period (usually a year) when the entire pipeline system has its maximum throughput. (Thus the day for this measure coincides for all customers.) Noncoincidental peak-day flows are the maximum volumes received by each customer on any day during a specified period. They are called noncoincidental because the days on which customers in a pipeline system experience their peak flow may not coincide.

[93]These laws include: the National Environmental Policy Act, National Historical Preservation Act, Endangered Species Act, Toxic Substances Control Act, Clean Air Act, Clean Water Act, Coastal Zone Management Act, Wild and Scenic Rivers Act, Wilderness Act, and National Parks and Recreation Act.

[94]In some instances, FERC may also issue a Section 7(c) certificate subject to "at risk" conditions. In such cases, the pipeline companies are not guaranteed authority to include costs in the rate base, and risks borne by the companies are not reduced. Under an "at risk" certificate, a pipeline company's risk is minimized only where it has fully contracted the capacity of a new line.

Synopsis of Utilization Measures

Pipeline Utilization at State Borders

The State-to-State measure of pipeline utilization used in this analysis is based on estimates of average-day pipeline throughput relative to estimates of system capacity at State boundaries. The average-day throughput was computed by dividing annual State-to-State flows in 1990 and 1994 (reported by pipeline companies) by 365 days. Average-day utilization was then derived by dividing the average-day flow by the estimated capacity level. This measure provided the basis for the analysis pertaining to usage of specific portions of a pipeline system and additionally some insight into the type of transportation service provided in the area.

But, because it uses averaged annual throughput volumes, the measure implies nothing about the availability of capacity during peak periods, except to the extent the average daily utilization approaches 100 percent. (Transportation levels on a pipeline system often vary from month to month, day to day, and even hourly.) As the computed utilization rate approaches 100 percent, it indicates only that the volume of gas moving through a specific geographic area on an average day during the year is close to estimated capacity. When this does occur, however, it is likely that the specific system location experiences some constraints during peak periods. A system that fully utilizes available capacity for short periods and not on a sustained basis throughout the year will show a lower utilization rate based on a daily averaging of annual throughput.

System-Wide Utilization

In order to evaluate operational and utilization levels of the various pipeline systems during the year, several flow-rate derivations were computed. These rates are based on a comparison of 1990 and 1994 monthly throughput on the entire pipeline system with the largest throughput (sales, transportation, and intercompany transfers) that occurred in any month over a 16-year period (1979-1994). They were developed to show the degree of difference that occurs on different types of systems over the year as seasons and demand change. In these computations, the highest monthly throughput during the 16-year period was used as the proxy for the system-wide capacity of the pipeline. (Using this baseline ignores changes in ownership of components of the various pipeline systems and construction that may have occurred throughout the period.) For 1990 and 1994, (1) average-month throughput, (2) high-month throughput, and (3) low-month throughput were each divided by the 16-year high-month throughput to derive three flow-rate percentages.

An analysis of the high, low, and average throughput rates provides some understanding of the load variability on a pipeline system during the year. For instance, systems with a high-month rate of 100 percent in 1990 had a record monthly throughput level in 1990. If these same systems also exhibited high average utilization rates at State border crossings, they may be constrained in their abilities to serve additional customers without capacity expansion. In contrast, systems with a relatively low peak-month throughput, but high aver-age utilization levels at specific points along the network, probably experience more localized capacity constraints.

Comparison of the system-wide average-month flow rates with utilization rates at State border crossings can provide insight into how representative the individual utilization rates are of the whole system. For example, if utilization rates are very high at State border crossings but the system-wide average-month rate is significantly lower, then there are likely to be elements of the system, probably wholly contained within a region or State, where utilization is low. Conversely, if utilization rates at State borders are very low but the system-wide average-month rate is significantly higher, then there are likely to be elements of the system where utilization is quite high. These areas are likely to be near supply regions where interstate pipelines interconnect and transfer large volumes of gas from one system to another.

Appendix B

Regional Profiles: Pipeline Capacity and Service

Appendix B

Regional Profiles: Pipeline Capacity and Service

The U.S. interstate natural gas pipeline system has grown substantially since World War II, maturing from a dedicated field-to-market structure into a national network. Of the lower 48 States, 27 are totally dependent upon the interstate natural gas transmission network for their natural gas supplies, which must be transported from only 11 States, located primarily in the Southwest and Central regions of the country. The requirement for natural gas pipeline service varies throughout the country. Each region possesses its own natural gas service profile based on factors involving weather, historical access to gas supplies, and population characteristics.

This appendix presents a brief profile of each of the geographic regions used in Chapter 3 of this report. The emphasis is upon the capabilities, that is, the capacity of each, of the interstate natural gas pipelines entering or exiting each region. It also provides some regional highlights concerning the growth in capacity of the interstate pipeline systems into or from each region and also at the level of planned additions to capacity over the next several years. Data on capacity, pipeline flows, pipeline utilization, and production and consumption are for the years 1990 and 1994. Data on proposed additions to capacity cover the period 1995 through 1998.

Producing Regions

Southwest Region

The Southwest Region is unique not only because of its long-held position as the major natural gas producing and consuming region, but also because it supplies the bulk of the gas consumed by all the other regions. It supplies a vast network of pipelines consisting of major interstate trunklines that deliver gas to each of the other regions of the country, smaller interstate lines that primarily serve the regional market, and intrastate pipelines that deliver gas exclusively within the States of the Southwest. More interstate natural gas pipeline companies operate within the Southwest Region than in any other, but it is the primary market for only a few of them.

Twenty of the major interstate pipelines originate in the Southwest (Figure B1). They extend to the Southeast Region through Louisiana and Arkansas, to the Central Region through Oklahoma and Arkansas, and to the Western Region through New Mexico. The Southwest Region currently exports about 60 percent (8.7 trillion cubic feet in 1994) of its production, which is 61 percent of the total natural gas consumed in the entire country.[95] Pipelines exiting the region have the capacity to accommodate as much as 35.7 billion cubic feet per day: 60 percent to the Southeast Region, 24 percent to the Central Region, 15 percent to the Western Region, and the rest to Mexico (Table B1). Much of the pipeline capacity to the Southeast traverses the region, delivering supply to the Midwest and Northeast; to a lesser degree this is also true for the pipeline capacity exiting to the Central Region, much of which is ultimately destined for the Midwest Region.

Between 1990 and 1994, regional export capacity increased by only 8 percent, but in incremental daily flow capacity that came to 2.7 billion cubic feet per day. While capacity additions into the Southeast Region represented only a 5-percent change from 1990, there was a 1.0 billion cubic foot per day increase in volume. While the volumetric increase was not comparable to the increase in capacity from Canada to the Northeast and Western regions, it still represented a substantial increase in capability to supply the Southeast Region. Export capacity to the Central Region showed a decrease during the period, but this was mainly due to a reversal of flows as more supplies began to emerge from the coalbed methane and tight gas fields of southern and central Colorado.

In recent years, partly because of improved recovery techniques and tax credit incentives, substantial development of coalbed methane resources has occurred in northern New Mexico and in the adjacent Central Region in southern Colorado. This has brought on additions to capacity along the interstate pipeline systems serving the San Juan Basin and nearby production areas.

[95]For purposes of this appendix, exports pertain to all volumes leaving a region for another region or country.

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Table B1. Interregional Pipeline Capacity, Average Daily Flows, and Usage Rates, 1990 and 1994

Receiving Region	Sending Region	Capacity (MMcf per day)			Average Flow (MMcf per day)			Usage Rate (percent)		
		1994	1990	Percent Change	1994	1990	Percent Change	1994	1990	Change
Canada	Central	66	66	0	9	44	-80	14	67	-53
	Midwest	2,093	1,211	73	1,443	961	50	69	79	-10
Total into Region		2,159	1,277	69	1,452	1,005	44	67	79	-12
Mexico	Southwest	844	354	138	117	38	208	14	11	3
	Western	45	45	0	7	5	40	16	11	5
Total into Region		889	399	123	124	43	188	14	11	3
Central	Canada	1,544	1,254	23	1,469	941	56	95	75	20
	Midwest	2,333	1,765	32	1,489	974	53	[a]90	[a]75	15
	Southwest	8,483	8,716	-3	4,722	4,119	15	56	[a]49	9
	Western	298	250	19	0	196	-100	0	78	NA
Total into Region		12,658	11,985	6	7,680	6,230	23	[a]67	[a]56	11
Midwest	Canada	2,780	2,161	29	2,487	1,733	44	89	[a]84	5
	Central	9,722	8,988	8	6,986	5,684	23	72	63	9
	Northeast	2,037	2,024	1	887	714	24	[a]56	[a]45	11
	Southeast	9,815	9,645	2	6,712	6,134	9	68	64	4
Total into Region		24,354	22,818	7	17,072	14,265	20	[a]71	[a]64	7
Northeast	Canada	2,135	467	357	1,656	309	436	78	66	12
	Midwest	4,803	4,572	5	3,185	3,464	-8	66	76	-10
	Southeast	4,783	4,782	0	3,705	4,086	-9	77	85	-8
Total into Region		11,721	9,821	19	8,546	7,859	9	73	80	-7
Southeast	Northeast	535	113	373	86	69	25	[a]75	[a]69	6
	Southwest	21,051	20,006	5	14,374	14,703	-2	68	73	-5
Total into Region		21,586	20,119	7	14,460	14,772	-2	[a]68	73	-5
Southwest	Central	1,745	1,283	36	1,122	572	96	[a]79	[a]58	21
	Mexico	350	350	0	19	0	NA	5	0	NA
	Southeast	335	335	0	15	15	0	[a]60	[a]60	0
Total into Region		2,430	1,968	23	1,156	587	97	[a]64	[a]69	-5
Western	Canada	3,546	2,406	47	2,866	1,871	53	81	78	3
	Central	1,164	365	219	917	196	368	79	54	25
	Southwest	5,351	4,340	23	3,383	3,910	-13	63	90	-27
Total into Region		10,061	7,111	41	7,166	5,977	20	71	84	-13
Total Lower 48 States		**85,858**	**75,498**	**14**	**57,656**	**50,738**	**14**	**[a]69**	**[a]70**	**-1**

[a]Usage Rate shown may not equal the average daily flows divided by capacity because in some cases no throughput volumes were reported for known border crossings. This capacity was not included in the computation of usage rate.

MMcf = Million cubic feet. NA = Not applicable.

Sources: Energy Information Administration (EIA). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database as of August 1995. **Average Flow:** "Natural Gas Annual 1994," draft report. **Usage Rate:** Office of Oil and Gas, derived from Pipeline Capacity and Average Flow.

Even though large volumes of natural gas leave the Southwest Region for other regional markets, significant volumes remain in the region to fulfill the high level of industrial demand encouraged over the years by proximity to production. In many respects, the States in the Southwest Region represent complete markets for natural gas, independent of other regions, and much of the movement of gas is completed by means of intrastate rather than interstate pipeline systems. The region has large petrochemical and electric utility industries drawn there by the local availability of substantial natural gas supplies.

In addition, the region has numerous underground storage reservoirs, most of which are used to store excess natural gas production during months of low consumption (Figure B1). Total storage capacity (over 1.6 trillion cubic feet) is the second highest of the regions. The region has temperate winters and long, hot summers. Louisiana and Texas are the second and third warmest States in the lower 48 States, which accounts for large electricity load levels for air-conditioning services.

Several of the major pipeline projects planned for development between 1991 and 1994, which were, in large part, to provide greater access to supplies from the Arkoma Basin in Arkansas/Oklahoma to the Northeast and Midwest markets, were not built. Part of the reason may have been planned Canadian import expansions and the already low utilization rates on the existing lines extending to the Midwest Region. In contrast, almost all of the 1991 through 1994 planned expansions into the Western Region were implemented. Capacity from the Southwest to the Western Region increased by 22 percent, to 5.3 billion cubic feet per day, but about 57 percent of the increase represented Central Region supplies traversing the region on their way to the California market.

Expansion projects currently planned for the Southwest Region, totaling 2.2 billion cubic feet per day through 1997 (see Figure 7, Chapter 3), reflect a pattern similar to other regions, that is, an emphasis on localized pipeline improvements and intraregional capabilities. More than 64 percent of the planned capacity additions are within the region. Several, however, do complement the interstate system in that they improve hub and/or underground storage accessibility, or they improve service to interstate pipelines. Only 14 percent of additional capacity is on the interstate system itself. Export expansions to Mexico represent 22 percent of announced expansions.

Central Region

The Central Region is becoming increasingly important as a supply area. It is the only region other than the Southwest to produce more gas than it consumes. Its1994 natural gas production of about 2.4 trillion cubic feet was about 10 percent of the total gas consumed in the Nation and it provided 3 percent of the natural gas consumed elsewhere in the country. This region had the largest production increase in the Nation between 1990 and 1994—557 billion cubic feet, or 32 percent. Most of the increased production came from newly developed fields in Colorado and Utah, and some expanded development of existing fields in Kansas and Wyoming.

The region's cold winters, combined with the lowest residential prices for natural gas of any region, help make the residential sector the largest consumer of natural gas in this region. The region has the second coldest weather of the six regions (see Table 3, Chapter 3). Plentiful supplies from production and storage sites within the region and adequate capacity on local transmission and distribution lines ensure that peak demands of residential customers are met during the winter.[96]

The region is the largest in area and the least populated. The total volume of gas consumed in the region in 1994, 1.7 billion cubic feet, was also the least of the six regions. Most of this gas is consumed for space heating, as it has the second highest percentage of households using natural gas.

While the Central Region consumes 73 percent of the natural gas it produces, and is the second largest gas producing region, its pipeline export capacity is a substantial 12.7 billion cubic feet per day (Table B1). Export pipeline capacity has increased 18 percent since 1990, primarily because of new pipeline capacity built to deliver the emerging Colorado/Utah supplies, mostly to California. Increased direct service to the Western Region was provided by the completion of the Kern River Pipeline system (700 million cubic feet per day) and indirectly through expansions on the Northwest Pipeline Company, El Paso Natural Gas Company, and Transwestern Gas Pipeline Company lines from the Southwest Region (Figure B2).

[96]Less natural gas is consumed in the Central Region than in any of the other five regions.

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The Central Region is also a major transit region for Canadian supplies imported into the United States. The northern section of the region receives large amounts of gas from Canada at Monchy near the Saskatchewan and Montana borders. Monchy is the second largest of the nine entry points for natural gas imports from Canada. There are two main flow patterns for natural gas through the region. One is from Canada across the northern States and into the Midwest. The second is from Oklahoma and Arkansas through the southeast part of the region into Illinois. Intraregional flows are from supply sources in Wyoming and Kansas into Denver, Colorado; from Kansas into Kansas City and St. Louis, Missouri; and from Kansas north through Nebraska to Iowa.

Much of the capacity in the region is designed to traverse the region. The pipeline systems with the largest capacities in the region are Northern Natural Gas Company, Natural Gas Pipeline Company of America, Panhandle Eastern Pipe Line Company, ANR Pipeline Company, and Northern Border Pipeline Company. All of these lines bring gas through the region to either Iowa or Illinois. The flow from the Southwest toward Chicago, Illinois is over the oldest long-distance transmission lines in the Nation. The Natural Gas Pipeline Company of America's line from the Texas Panhandle to Chicago was laid in 1931, traversing Kansas and Iowa, while the Panhandle Eastern Pipe Line Company line from the Texas Panhandle to Illinois, also laid in 1931, traverses Missouri. Most of the major lines in Wyoming, Montana, and Colorado were built before 1932, and the lines that serve Kansas have been in place for 70 years.

The increase in capacity to the Midwest Region that occurred over the past several years came principally from expanded service on the Northern Border Pipeline system. Some minor increases in capacity also occurred on routes serving the Midwest Region out of Kansas. Existing capacity from the latter was capable of handling a 90 percent increase in flows from expanded production in the Hougoton Basin.

Although planned additions to capacity in the region between 1995 and 1997 amount to 3.0 billion cubic feet per day, 97 percent of this is capacity directly or indirectly exiting the region. Principal among the new pipelines planned for the region are the Altamont Pipeline (1996, 719 million cubic feet per day) and the Transcolorado Pipeline (1996, 300 million cubic feet per day). Major expansions include the Kern River Pipeline (452 million cubic feet per day), which is tied into the Altamont project, the Northern Border Pipeline Company (336 million cubic feet per day), Northern Natural Pipeline Company (106 million cubic feet per day) and Natural Gas Pipeline Company of America (900 million cubic feet per day).

Consuming Regions

Western Region

Population in the Western Region has increased rapidly. During the 1980's, Nevada and Arizona were the fastest growing States in the Nation, sustaining population increases of 51 and 35 percent, respectively. These rates are considerably higher than for other States, with only Florida growing faster. In addition, California, already heavily populated, grew by 26 percent during the same period.

Because the Western Region has limited indigenous natural gas reserves, its gas customers rely on the interstate pipeline network to bring supplies relatively long distances from major domestic and Canadian producing regions. Yet, geographic features and environmental regulations limit access to gas supplies. Environmentally sensitive terrain limits the pipeline corridors providing access to supplies in the East. Offshore leasing moratoria impede further development of resources in the Pacific.

About two-thirds of the capacity into the region is on pipeline systems that carry gas from the Rocky Mountains area and the Permian and San Juan Basins. These systems enter the region at the New Mexico-Arizona and Nevada-Utah State lines. The rest arrive on pipeline systems that access Canadian supplies at the British Columbia-Idaho and Washington State border crossings.

Only five interstate pipeline companies provided service into the region in 1994, the fewest serving any region (Figure B3). Capacity entering the region was also the lowest of all gas-importing regions, approximately 10 billion cubic feet per day (Table B1). A fifth interstate system, the Mojave Pipeline, is mainly a provider of transportation services (400 million cubic feet per day) from Arizona into California. It eventually merges with the Kern River Pipeline to serve customers in southern parts of the State.

The electric utility industry is a major user of natural gas. In three of the six Western Region States (Arizona, Nevada, and California), the electric utility industry accounts for 24 percent or more of total natural gas deliveries to consumers. Coincidently, Federal and State environmental regulations are encouraging more natural gas use, particularly in applications where petroleum products and coal dominate the market. In some parts of the region, regulations to limit atmospheric emissions may make natural gas the only fossil fuel that can be used for electric power and steam generation. The region is also the leader in demonstration projects for compressed natural gas vehicles.

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During the 1980's combined pipeline and storage capacity was not adequate to meet peak-period demand. In California, capacity-induced curtailments to interruptible customers during peak periods became a regular element of the natural gas market. These curtailments and the significant potential for further market expansion within the region resulted in intense competition for existing pipeline and storage capacity. In response to the situation, and with expectations of greater market growth, several new pipeline systems were built and several existing ones were expanded.

Capacity into the Western Region increased overall by more than 41 percent, or 2.9 billion cubic feet per day between 1991 and 1994. The majority of this increase occurred on routes transporting gas from Canada, where 47 percent more capacity was implemented. Pacific Gas Transmission Company and Northwest Pipeline Company accounted for all of these capacity additions. In spite of a general economic downturn in the region during the period, particularly in California, average capacity usage rates declined only slightly, by 2 percentage points, from 1990.

On a percentage basis, however, the largest growth in capacity, 219 percent, was on routes bringing supplies from States in the Central Region—Wyoming, Utah and Colorado. With the completion of the Kern River Pipeline Company line into California, capacity from the Central Region reached 3.5 billion cubic feet per day. Average usage rates on lines from the Central Region climbed from 54 percent in 1990 to 79 percent in 1994, principally from the almost full utilization of the Kern River Pipeline.

Added capacity from the Southwest Region, which also carries supplies from Colorado’s coal-bed methane fields, amounted to over 1.0 billion cubic feet per day. Transwestern Pipeline Company and El Paso Natural Gas Company added the bulk of this new capacity. It, however, faced a soft market. Capacity serving California from the Southwest Region displayed the largest drop in usage within the interregional network. While the enhanced oil recovery (EOR) market supported and maintained high average utilization rates (79 percent) on the pipelines originating in Central Region, capacity utilization from the Southwest Region fell by 27 percent.

The level of pending capacity additions into the Western Region currently stands at only 0.5 billion cubic feet per day (through 1997) compared with 2.9 billion cubic feet per day completed between 1991 and 1994 (Table B1). One project accounts for a large portion of this proposed capacity expansion. The Kern River Pipeline increment based upon the Altamont pipeline project is scheduled to bring in Canadian supplies sometime in 1996. However, the Altamont itself has been postponed several times because of market conditions and delays in getting approval from the FERC.

Within the region itself, additional pipeline capacity is being developed to serve new markets. The Mojave Pipeline extension proposes to provide an additional 0.5 billion cubic feet per day to the north and north central area of the State, bringing supplies up from the south. The Tuscorora Pipeline would bring 0.1 billion cubic feet per day from Oregon (Canadian Gas) to the northeast part of the State in the Lake Tahoe area. And, although current usage rates are down, El Paso Natural Gas has planned several projects that will improve its local deliverability and increase efficiency by improving or altering some current flow patterns.

Northeast Region

The Northeast consumes more energy than any other region, although only 18 percent is in the form of natural gas. It is the most heavily and densely populated of the six regions. Because regional production is quite limited, natural gas customers in the Northeast Region must rely on an extended interstate pipeline system to bring supplies from producing areas outside the region.[97] At one time, the Northeast was a major source of natural gas; in fact, manufactured and natural gas first became commercially available there over 175 years ago. A complex distribution network of pipelines has long been available. Similarly, the region has considerable access to underground storage since gas storage fields were first created and used in the area.

When local supplies were being depleted in the 1920's and 1930's, trunk pipelines were built to bring gas supplies from the Southwest Region to replace gas manufactured for residential use. However, the Northeast was the last region to be linked to the interstate pipeline network, with some areas only getting service as recently as 1966. Today the interstate pipeline companies serving the region have access to supplies from all major domestic gas-producing areas and Canada (Figure B4). In addition, liquefied natural gas is imported into Massachusetts from Algeria.

Transportation capacity into the northeastern market increased by more than 19 percent, or 1.9 billion cubic feet per day between 1990 and 1994 (Table B1). This made it the second most active regional natural gas market during the period. The vast majority of this new capacity provided greater access to Canadian supplies. Principal projects completed between 1991 and 1994 included the intrastate Empire Pipeline (affiliated with ANR Pipeline Company—0.5 billion cubic feet per day), the Iroquois Pipeline (0.6 billion cubic feet per

[97]Regional production of natural gas, the equivalent of 14 percent of area consumption in 1990, fell to 10 percent in 1994.

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day), and Tennessee Gas Pipeline Company's expansion of its Niagara import facilities (by 0.4 billion cubic feet per day). Utilization of this new capacity in 1994 was above 95 percent except for the Empire line, which primarily serves the upper New York intrastate market.

The two main flows of gas into the region are from the Southeast into Virginia and West Virginia, and from the Midwest into West Virginia and Pennsylvania. Gas then moves within the region toward New York City and Boston. In 1994, the interstate pipeline system serving the region had the capacity to move 4.8 billion cubic feet per day from the Southeast and Midwest regions.

The region has large swings in gas demand because of weather. Overall, it is the third coldest of the regions, with some of the coldest States in the Nation at its northern limits. Withdrawals from storage are necessary to meet peak demand, as total capacity entering the region plus regional gas production are only about two-thirds of the region's peak demand. Gas demand is driven by the growing, highly populated urban corridor that stretches from Boston, Massachusetts to Richmond, Virginia.

Capacity expansions of 2.8 billion cubic feet per day, 15 percent above current levels, have been proposed by regional suppliers. This represents 32 percent of total proposed expansions nationwide. Of that, 0.4 billion cubic feet per day is additional capacity into the region. Long dependent on fuel oil, the Northeast has seen a steady increase in the availability of, and demand for, natural gas in recent years. The expected growth markets for the planned expansions will be the co-generation facilities and industrial customers.

Southeast Region

The Southeast Region is the least developed market for natural gas in terms of per-capita consumption. In fact, natural gas accounts for only a small percentage of the total energy consumed in the region. Nevertheless, because of its location, numerous interstate natural gas pipeline companies operate through the region (Figure B5), carrying significant supplies through the region to the Northeast and the Midwest. During peak periods, the interstate pipeline system has the capacity to move up to 21.6 billion cubic feet into the region, principally from the Southwest Region (Table B1). This is the second-largest capacity level for any region. The region has an exit capacity level to the Northeast and Midwest of 14.8 billion cubic feet per day.

The region has temperate weather conditions and has historically had low winter demand for heating. Overall, the region has the mildest weather of any region, with Florida being one of the warmest States in the Nation.

The region has some of the fastest growing States. While it is still only the third most populous region, with 46 million people, population increased substantially during the 1980's. The population of Florida has increased by more than 33 percent since 1980; it is now the fourth most populous State. Georgia was the eighth fastest growing State during the 1980's.

Essentially all of the interstate natural gas pipeline capacity entering the region comes from the Southwest Region. More than 70 percent of this capacity is directed out of the region, with 9.8 billion cubic feet per day into the Midwest and 4.9 billion per day into the Northeast Region. The region is a net consumer of gas, with only Mississippi, Alabama, and Kentucky producing significant quantities of gas.

Capacity into the Southeast Region grew by about 7 percent between 1990 and 1994. Most capacity additions occurred within the region. The major projects completed were the Florida Gas Transmission expansion, the Mobile Bay Pipeline, and the Transcontinental Gas Pipeline southern expansion. Noteworthy were the additional pipeline expansions serving the northern North Carolina market. Several pipelines from the Northeast Region (Columbia Gas Transmission and Transcontinental Gas Pipeline Company) extended their systems into the Southeast Region market in 1993. On the other hand, several major projects announced in 1990 were subsequently withdrawn, postponed, or canceled outright. Among these were the Cornerstone Pipeline (0.6 billion cubic feet per day), the Tennessee Gas Pipeline West-to-East crossover (0.5 billion cubic feet per day), and the Texas Eastern Pipeline OK-AR pipeline (0.5 billion cubic feet per day).

Expected and actual growth in demand for natural gas as an electric utility plant fuel (and its use as other than a space heating fuel) has spurred new construction in the region. A prime example is in the State of Florida. Installed capacity on the Florida Gas Transmission (FGT) system, which supplies almost all the natural gas to the eastern and southern parts of State, increased by 15 percent, from 820 in 1990 to 943 million cubic feet per day at the end of 1994. Another 532 million cubic feet per day became operational in March 1995, yielding an 80-percent increase since 1990. The electric utility industry accounts for over 50 percent of total natural gas consumption in the State. Indeed, citing expected future growth in this sector, FGT has proposed to FERC to expand its service capability even further. Proposed additions to capacity into the region over the next several years amount to a substantial 915 million cubic feet per day, up 4 percent from 1994 levels, but below what has been added since 1990.

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Midwest Region

An intricate, long-distance natural gas transmission network has evolved over the past 70 years to serve the Midwestern market (Figure B6). Today 15 interstate pipeline companies have the capacity to move 24.3 billion cubic feet of gas into the region per day (Table B1). The total capacity of the interstate pipelines entering the region is larger than for any other region.

The current level of pipeline capacity into and within the Midwest was essentially reached in the late 1970's. Except for the completion of the Northern Border Pipeline (the eastern leg of the Alaska prebuilt system), which provided increased availability of gas supplies from Canadian sources by way of the Central Region, construction and system expansion during the past decade was minimal. However, pending and potential capacity expansion projects provide some indication that growth in natural gas consumption is expected over the next several years. Capacity additions into the Midwest Region between 1991 and 1994 were 1.5 billion cubic feet per day, an increase of 7 percent over 1990 levels. No new major pipelines were constructed in the region although a number of expansion projects were completed. Primary among these were additions to the Great Lakes Transmission System (a 41 percent increase in capacity), the Northern Border Pipeline (36 percent) and ANR Pipeline Company (18 percent in Michigan and Indiana).

The interstate pipeline system extending into the Midwest Region taps the major gas-producing areas of East Texas, Louisiana, and offshore Gulf of Mexico for about one-half of its supplies, and to southwest Kansas, Oklahoma, and north Texas for an additional one-third. Regional production, principally from Ohio and Michigan, provides a little more than 6 percent of gas consumption in the region. The remaining supply comes from Canada.

Several characteristics of the Midwestern market underlie its status as the Nation's second largest market for natural gas and help explain its extensive pipeline network. The region is weather-sensitive, with cold winters and moderate summers. Minnesota and Wisconsin are among the coldest States in the Nation, and the other four States in the region are colder than the national average. It also has a number of major population centers and is the second largest of the six regions in population. The large number of residential space-heating customers, combined with the cold winters, result in large residential requirements for natural gas. The geographic position between the Central and Northeastern United States has resulted in a significant portion of the region's pipeline system capabilities being reserved for deliveries beyond its borders. Eight major pipeline systems serving the region also serve customers in the Northeast Region or in eastern Canada. Customers in eastern Canada receive Canadian gas that was transported through the Midwest Region for delivery into Ontario.

The interstate pipeline systems operating in the area are primarily trunk pipeline operations, transporting large volumes of gas from distant supply sources to local distributors. They differ greatly in size, type of service market, and the importance of the Midwest market to their overall operations. While the two most northern States, Wisconsin and Minnesota, as well as portions of Michigan, are serviced by pipelines importing Canadian supplies, the southern portion of the region is serviced primarily by the major trunklines coming from the Southwest.

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Appendix C

Data Sources

Appendix C

Data Sources

The data presented in the body of the report came from many sources and often required some adjustment to provide information on a comparable basis for use in the analysis. This appendix provides detailed information on the methodology and source material used to develop the estimates of 1990 interstate pipeline capacity at State borders and the changes in energy usage patterns from 1980 through 1989.

The following is a list of the data sources discussed in this appendix.

- Annual pipeline company reports filed with the Federal Energy Regulatory Commission (FERC) under 18 CFR 260.8, Format 567, "System Flow Diagrams"

- FERC Form 11, "Natural Gas Pipeline Monthly Statement"

- Energy Information Administration, Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"

- *Natural Gas Annual*, DOE/EIA-0130, various issues.

Pipeline Capacity

The measure of pipeline capacity that was estimated and addressed in this report is the daily capacity of the interstate natural gas pipeline network at regional and State boundaries. Specifically it is an estimate of the maximum volume of gas that can be transported under normal operating conditions for a sustained period of time. While the pipeline systems have considerable operational flexibility to increase deliveries of natural gas to certain areas above design capacity for short periods of time, this often means either reduced deliveries elsewhere or the use of line packing. Neither measure is likely to be sustainable for more than a short period of time.

Information on capacity levels for the interstate pipeline systems is generally available from filings at the Federal Energy Regulatory Commission (FERC). However, this information is typically associated with compressor stations and not State border capacity. Thus, an approach was required to estimate the State-to-State capacities on the pipelines. Further, while there is a regulatory requirement for the submission of design information, the terminology provided in the submissions sometimes is unclear as to whether the data provided by a company are in fact the information requested.

The original compilation of pipeline capacity estimates was done by the Energy Information Administration during 1991 and 1992, using 1990 as the base year. The initial approach taken to derive the State-to-State capacity information was the following:

- Develop initial capacity estimates using the compressor station data from FERC Format 567, "System Flow Diagrams."

- Adjust initial estimates using delivery requirements of customers located between the State line and the station and for any contracted receipts from other pipelines.

- When compressor station data were unavailable on Format 567, derive a statistical estimate using a regression equation based upon the diameter(s) of the pipeline segment in question.

- Impute remaining missing values using proxies for capacity. Data used for this purpose included the contract demand data (CD) that were available for the years 1988 and 1989 for pipeline sales customers.

- Cross check the State border capacities for reasonableness, using contract demand levels (if not used as a proxy for capacity), flow data from Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," and consultations with FERC staff and company officials.

Capacity estimates for 1994 were developed using the 1990 estimates as a starting point. Next, the 1994 and 1990 FERC Format 567 "System Flow Diagram" were compared to determine to what extent the throughput capabilities of the pipeline compressor stations had changed. In addition, comparisons of receipt and delivery point volumes were also performed to determine changes in peak-day deliverabilities and as a replacement for contract demand data that were no longer current. Available data on pipeline construction projects proposed to be built between 1991 and 1994 and their current status were also factored into the estimates. These comparisons were done, to the extent possible, through comparative analyses of updated databases. Initial estimates of revised capacity levels were produced and displayed on annotated pipeline maps.

These initial estimates were then forwarded to willing pipeline company staff for their review and evaluation. If company input was not available, the estimates were given to FERC staff for an evaluation. These input were used to settle upon a final estimate.

The initial (1990) estimates of capacity on a pipeline segment at a State border were based on reported compressor station throughput, the daily output of whichever compressor station appeared to be closest to the State border. The working assumption was that throughput capability, even if only an estimated flow under current operating conditions, of any compressor station is a reasonably good estimate of peak-period throughput at that point on the line. (Compressor station output may be a "constraint" on throughput when downstream pipeline diameter, and other characteristics of the segment, may allow the physical pipeline to handle greater loads than required under current customer peak-day commitments. Conversely, the designed compressor output may be greater than can be sent through existing pipeline configurations.)

When no delivery or receipt points were between the selected compressor station and the State line, the capacity at the State border was assumed to equal the station capability, even though some friction losses would occur because of the distance between the line and compressor. When data were available for both receipts and contract demand deliveries between the compressor station and the State line, then the initial capacity estimates were adjusted to account for these volumes.

In some cases, peak-day information rather than design capacity was reported on FERC Format 567. These estimates were considered a reasonable proxy for capacity.

Under certain conditions, contract demand (CD) data were used to estimate capacity levels at a State border. CD data were assumed to be a reasonable reflection of current peak-day demands on the pipeline system and therefore a close approximation of the capability or capacity of the pipeline to supply those customers. A pipeline company's CD commitment levels within a State were used as a surrogate for a measure of that pipeline's capacity into the State when the pipeline system, or a branch, terminated in the State. Even in this instance, however, the pipeline company could meet a portion of its commitments from sources within the State borders.

In some cases, compressor station data and contract demand data were inadequate to develop an initial capacity estimate, and other methods were pursued to make the initial capacity estimate. For instance, regression equations to estimate capacity were developed using a universe of 814 compressor stations with known pipeline diameters, capacity, and pressure, extracted from the Format 567 filings. The results indicated that diameter alone was a good predictor of capacity in these equations.

Average Daily Pipeline Flow

The data source for actual average daily pipeline volume flows across State borders was Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition." In addition, these data are the basis for supply, consumption, and transportation volumes presented on each State in this report.

The respondent universe of the Form EIA-176 includes interstate and intrastate pipeline companies; investor and municipally owned natural gas distributors; underground natural gas storage operators; synthetic natural gas plant operators; and field, well, or processing plant operators that deliver natural gas directly to consumers and/or transport gas to, across, or from a State border through field or gathering lines.

The average daily flow volumes presented in the "Interregional Capacity" tables in Chapter 3 are based upon preliminary 1994 data extracted from Form EIA-176. They are the sum of data that can be identified as volumes brought across a border: onsystem purchases received at a State border, plus transportation and/or exchange receipts received at a State line, plus transported into the report State. The data on Form EIA-176 are annual; average daily levels were computed on a 365-day basis.

Greater detail concerning Form EIA-176, its background and EIA processing methodology, may be found in the appendices of the EIA publication, *Natural Gas Annual 1990* (DOE/EIA-0131).

System Flow Rate Data

The pipeline system-wide flow rate data discussed in Chapter 3 and used for utilization analysis are based on monthly throughput volume data reported on FERC Form 11, "Natural Gas Pipeline Monthly Statement." These data for the period January 1979 through December 1994 are maintained and available on computer tape.

Transportation, sales, and intercompany transfer throughput volumes are reported, but for the total pipeline system only. As a result, these data cannot be used to compute regional or State-level utilization levels. However, the historical data were used to identify and quantify the largest monthly throughput level occurring on individual pipeline systems over 16 years, 1979 through 1994. Average monthly throughput rates for 1989 and 1994 were then divided by the largest monthly throughput (which was used as an approximation of a 100-percent load factor or a surrogate measure for full capacity utilization) to estimate the overall relative flow rate (throughput) on the various pipeline systems in 1994.

Maps and Mapped Data

The geographic displays in the main body of this report were produced, in whole or in part, using the EIAGIS-NG Geographic Information System. The system consists of a series of site-specific databases and digitized pipeline maps residing in a PC (personal computer) environment. The pipeline map files were developed from publicly available sources, although in some cases, more detailed maps were provided by the individual pipeline companies. Currently, the EIAGIS-NG contains map data for 60 interstate and 55 intrastate pipeline companies.

Each interstate pipeline map file also contains profile (attribute) data, such as pipe diameter, maximum allowable pressure, looping, etc., for each pipeline segment. These data were compiled from the pipeline system schematic contained in the FERC Format 576 "System Flow Diagram." The individual databases supporting the system include such pipeline related data as:

- Compressor stations
- Delivery points
- Receipt points
- Major interconnections
- State border crossings and capacity levels.

Nonpipeline-related databases include:

- Underground storage sites
- Planned underground storage projects
- Proposed construction projects
- Local distribution company service areas
- Exports and imports
- Market hubs
- Electric power plants, etc.

The principal geographic data used in this report to compile capacity estimates were the pipeline maps and their receipt, delivery, interconnection, and compression station points. Planned and existing underground storage site data were used to develop estimates of supplemental peak day deliverability to the pipeline network.

U.S. Regional Definitions

The six regions used in this report were based in whole or in part upon the 10 Federal regions originally defined by the Bureau of Labor Statistics. The groupings are as follows:

Northeast Region—*Federal Region 1*: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. *Federal Region 2:* New Jersey, and New York. *Federal Region 3:* Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, and West Virginia.

Southeast Region—*Federal Region 4:* Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee.

Midwest Region—*Federal Region 5:* Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.

Southwest Region—*Federal Region 6*: Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.

Central Region—*Federal Region 7:* Iowa, Kansas, Missouri and Nebraska. *Federal Region 8:* Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming.

Western Region—*Federal Region 9:* Arizona, California, and Nevada. *Federal Region 10*: Idaho, Oregon, and Washington.

Appendix D

FERC Ratemaking Process

Appendix D

FERC Ratemaking Process

The Natural Gas Act of 1938 (NGA) gave the Federal Energy Regulatory Commission (FERC) broad authority to regulate the interstate sales and transportation of natural gas. FERC ensures that rates are reasonable and nondiscriminatory by presiding over rate hearings. During a rate hearing, the pipeline company is required to justify its proposed rates by providing detailed information on its costs and proposed service levels (volume and demand requirements). Before deciding on the appropriate cost and service levels that will be used in determining pipeline company rates, the regulatory process provides all concerned parties the opportunity to present testimony to FERC.

The ratemaking process can be separated into five distinct steps:

- **Determine the overall costs that should be recovered in the rates.** FERC generally uses a historical cost approach to ratemaking in which actual costs for a recent 12-month period (base period) are adjusted for known and measurable changes expected to occur within nine months of the end of the base period. FERC sets up a "test period cost of service" that includes all pipeline company costs of providing service, including a fair return on investment. The individual components of the cost of service are discussed in greater detail below.

- **Separate the "test period cost of service" into pipeline functions such as gathering, transmission, and storage.**

- **Classify "functionalized" costs into demand and commodity components.** Variable costs, costs that vary with the volume of gas flowing through the pipeline, are classified as the commodity component. Depending on FERC's ratemaking goals, fixed, or nonvariable, costs are allocated to the demand and/or commodity component. Because the natural gas pipeline industry is very capital intensive, the majority of pipeline company costs are fixed.

- **Allocate demand and commodity components among pipeline company services.** Demand costs are traditionally allocated among services based on customer capacity requirements, while commodity costs are allocated on a volumetric basis. Part of the allocation process may also incorporate the distance gas travels to the customer.

- **Design unit rates.** Unit rates are developed by dividing the allocated demand and commodity costs by billing units for the respective services. Rates can be designed to incorporate a one-, two-, or three-part rate structure of billing. A one-part rate is designed to recover demand and commodity costs in a single volumetric charge—the customer is billed based on the number of gas units it consumes or transports. In a two- or three-part rate structure, reservation rates are designed to recover demand costs while volumetric rates recover commodity costs.

Rates are also designed to reflect the pipeline company's quality of service. For example, firm service rates recover more of the pipeline company demand costs than interruptible service rates. Firm customers have first call on capacity contracted for, while in cases of a shortage, interruptible customers may be bumped from the system. Hence, interruptible rates are usually one-part rates that are generally lower and include only a small portion of the demand cost.

While this description of the ratemaking process appears fairly straight forward, FERC can influence the ratemaking process to achieve policy goals that are pertinent to prevailing market conditions.[98] To achieve policy goals, FERC uses the cost classification aspect of the ratemaking process to classify fixed costs as either demand or commodity or some mixture of the two.

During the early 1980's FERC adopted the modified fixed-variable (MFV) method of cost classification. MFV classified all fixed costs as demand costs except for the return on equity and related income taxes (and sometimes fixed production and gathering costs) which were classified as commodity costs. This had the effect of lowering overall transportation rates. FERC adopted the MFV method to promote two goals: first, to reduce underutilization of the national natural gas pipeline system and second, to make natural gas more competitive with alternate fuels.

In addition to the MFV classification, FERC proposed to split demand costs between two demand components: the (D-1) component recovered demand costs through a peak-day charge, and the (D-2) component recovered demand costs through an annual demand charge. FERC proposed this change in rate

[98]FERC Docket Nos. RM91-11-000 and RM87-34-065, Order No. 636, p. 120.

design to mitigate the cost-shift impact on low-load-factor customers of the move to MFV rates.

In 1989 FERC once again reviewed its ratemaking policies in light of institutional changes that were affecting the pipeline industry, such as open-access transportation and the decontrol of natural gas wellhead prices. As part of this review, FERC released its *Policy Statement Providing Guidance with Respect to the Designing of Rates*, which evaluated the effectiveness of different aspects of ratemaking in meeting the goals of rationing transportation capacity and maximizing throughput. Specifically, FERC discussed seasonal rates, capacity adjustments, discounted transportation, maximum interruptible rates, and the classification of fixed and variable costs to demand and commodity charges. In its Policy Statement, FERC suggested that to meet the goals of rationing capacity in peak periods and maximizing throughput, the annual demand component associated with the MFV rate design should be eliminated and costs formerly recovered under the D-2 component be moved to the D-1 component. This essentially was a transition to the present practice of using straight fixed-variable (SFV) rate design prompted by Order 636.

While the changes in cost allocation and rate design initiated by FERC do not affect the total costs collected by the pipeline company, they do affect the overall unit cost of service charged to the customer. For example, the SFV rate design collects a larger share of fixed costs via the capacity reservation charges than does the MFV design. As discussed in the corridor rate study, the shift of costs to reservation charges increases the average unit cost of service to customers whose peak requirements are larger than their average annual requirements. Therefore, excluding any other changes in costs and services, the switch from MFV to SFV would increase the average unit cost of service to low-load-factor customers.

Components of the Pipeline's Cost of Service

The starting point for designing rates is to determine the total cost of service necessary for the pipeline company to provide service to its customers. The cost of service contains five base components.

- **Return on Rate Base.** The return is calculated by multiplying the allowed rate of return by the company's rate base. The rate base is generally calculated as net plant (gross gas plant in service plus construction work in progress less the accumulated depreciation, depletion and amortization) plus prepayments and inventory items (gas stored underground, materials and supplies, etc.) less accumulated deferred income taxes. The rate base is the foundation on which the natural gas pipeline company earns its profit (return on equity) and its financing costs (return on debt).

- **Operation and Maintenance (O&M) Expenses.** O&M expenses include the labor and materials expenses required for the pipeline company to perform its day-to-day service. These expenses are related to the production, distribution, transmission, and storage functions of the pipeline company and include the costs for customer services and administrative and general support.

- **Depreciation, Depletion and Amortization (DD&A) Expenses.** This represents a charge or credit to income taken against the decrease in value of an asset over a period of time. Some of the factors considered in determining DD&A are wear and tear, obsolescence, and salvage value.

- **Income Tax Allowance.** Income tax allowance provides the pipeline company a method to recover the booked cost of Federal and state income tax expenses from its rate payer. The income tax allowance is computed by multiplying the return on equity, as adjusted for tax purposes, by an income tax factor. The income tax factor is generally computed by dividing the tax rate by one minus the tax rate.

- **Other Operating Expenses.** These expense items include taxes other than income taxes, revenue credits, deferred income taxes, and other such miscellaneous expenses.

A number of factors have a natural tendency to influence rates over time. For example, depreciation of the natural gas plant facilities will tend to reduce rates over time. Depreciation reduces the return component of rates by reducing the rate base on which return is computed. If pipeline companies did not restore depreciated plants or invest in new plant facilities, rates would decline over time.

Increases in any one of the cost items identified above will place upward pressure on average unit rates, while decreases will tend to lower rates. However, the ability of a component to affect rates significantly is related to its share of the total cost of service. A large decrease in a component does not automatically lead to a large decrease in average unit rates. For example, between 1988 and 1994, other expenses almost doubled, however, they represent only a small portion of the total cost of service, and the increases did not dramatically increase average unit rates (Table D1). In fact, the rate base has increased by about $6 billion since 1988.

Unlike individual rate components, relative changes in deliveries to customers can and do have significant and inverse effects on average unit rates. For example, the 1994 sample average unit rate is $0.59 per thousand cubic feet. The unit rate calculated using 1988 volumes is $0.68 per thousand cubic feet. This indicates that the 16-percent increase in volumes from 1988 to 1994 results in a 12-percent decrease in average unit rates.

Table D1. Aggregate Cost of Service and Rate Components for Major Interstate Pipeline Companies, 1988-1994

	1988	1989	1990	1991	1992	1993	1994
Aggregate Cost of Service (nominal dollars, thousands)							
Return on Rate Base							
Total Rate Base	$20,219,700	$18,943,698	$23,177,756	$25,711,373	$26,307,394	$26,136,744	$25,617,891
Percent Return on Equity	6.43	6.39	6.64	6.62	6.37	6.63	5.74
Percent Return on Debt	5.05	5.30	4.79	4.77	4.27	4.84	4.42
Equity portion of Return	1,300,127	1,210,502	1,539,003	1,702,093	1,675,781	1,732,866	1,470,467
Debt portion of Return	1,021,095	1,004,016	1,110,215	1,226,432	1,123,326	1,265,018	1,132,311
O&M Expenses (excluding cost of gas)	6,965,146	8,035,884	5,514,858	8,411,606	7,162,898	6,794,636	5,419,034
Other Expenses							
Depreciation, Depletion, Amortization	1,550,952	1,343,755	1,348,979	1,301,518	1,118,227	1,528,583	1,307,123
Income Taxes	724,834	681,867	866,395	989,253	1,020,474	1,012,925	847,512
Other Expenses	508,255	733,191	677,666	15,130	739,712	721,141	916,759
Total Aggregate Cost of Service	$12,070,409	$13,009,215	$11,057,116	$13,646,032	$12,840,418	$13,055,171	$11,093,205
Natural Gas Delivered to Consumers (billion cubic feet)	16,320	17,102	16,820	17,305	17,786	18,488	18,851
Unit Rate Components (1994 dollars per thousand cubic feet)							
Total Return on Rate Base	$0.17	$0.15	$0.18	$0.18	$0.16	$0.17	$0.14
O&M Expenses (excluding cost of gas)	0.52	0.55	0.36	0.52	0.42	0.38	0.29
Other Expenses							
Depreciation, Depletion, Amortization	0.12	0.09	0.09	0.08	0.07	0.08	0.07
Income Taxes	0.05	0.05	0.06	0.06	0.06	0.06	0.04
Other Expenses	0.04	0.05	0.04	0.00	0.04	0.04	0.05
Total Unit Cost of Service	$0.90	$0.88	$0.73	$0.85	$0.75	$0.72	$0.59

O&M = Operating and maintenance expenses.

Sources: 1988-1989: Energy Information Administration, Statistics of Interstate Natural Gas Pipeline Companies 1991 (December 1992).
1990-1994: Federal Energy Regulatory Commission (FERC) Form 2, "Annual Report of Major Natural Gas Companies", Balance Sheet, O&M Expenses and Statement of Income files from FERC Gas Pipeline Data Bulletin Board System.
The Federal portion of the income tax expense is calculated by multiplying the equity portion of return by the Federal tax factor.

Appendix E

Corridor Rate Analysis Results

Appendix E

Corridor Rate Analysis Results

To compare the transportation rates for delivering gas from various supply areas to selected market areas, over time, the maximum firm transportation reservation and usage rates (including surcharges) were converted to one-part usage rate equivalents. These one-part rates represent the total per unit cost of transporting gas from supply to market for two customer load profile types (100-percent load factor and 40-percent load factor). The results of the study present the trends in these transportation rates and provide some insight into the change in the cost of moving gas.

Source of Rate Component Data

Most of the rate component data for 1991 and 1994 were taken from the Foster Associates, Inc., *Competitive Profile of U.S. Interstate Pipeline Companies* (October 1991) and *Competitive Profile of Natural Gas Services* (December 1994), respectively. The 1994 data from Foster Associates' report were compared with the pipeline company tariff rates obtained using the Federal Energy Regulatory Commission Automated System for Tariff Retrieval (FASTR). FASTR was also used to obtain Kern River Gas Transmission Company's 1994 base transportation rates that were used in the study. The 1991 rate components for Florida Gas Transmission Company are from H. Zinder & Associates, *Summary of Rate Schedules of Natural Gas Pipeline Companies*, March 1991. The components used to compute unit rates include the reservation charge, the usage charge, the cost of fuel retained by the pipeline company, and all applicable surcharges. Surcharges are included in the reservation as well as usage portions of the rate components. The specific surcharges included in the rate components vary among the pipeline companies. However, all pipeline companies include Gas Research Institute (GRI) funding and Annual Charge Adjustment (ACA) surcharges. Additional surcharges may include Gas Supply Realignment (GSR), Stranded Costs, and Purchased Gas Adjustment (PGA) surcharges. The cost of fuel retained by the pipeline company is calculated by multiplying the retention rate by the unit cost of gas. Therefore, the unit cost of fuel retained by the pipeline company will vary depending on the supply source of the gas.

In at least one instance, seasonal rates were filed by a pipeline company included in the corridor rate study. Noram Gas Transmission Company (Noram) has separate 1994 rates applicable for service during the winter (November through March) and summer (April through October) seasons. The seasonal rates were converted to a levelized rate by weighting the respective rate by the number of months in the season and dividing the sum of the two weighted amounts by 12. For example, the Noram winter reservation charge is $9.39 per million Btu (MMBtu) and its summer reservation charge is $3.79 per MMBtu (excluding surcharges). Therefore, the levelized rate is the sum of the products $9.39 times 5 and $3.79 times 7 divided by 12 or $6.12 per MMBtu. The surcharge is added to the levelized rate to arrive at the reservation charge component used in the corridor rate study.

A pipeline company will sometimes offer firm transportation rates under various rate schedules which accommodate differences in its customers' characteristics. For example, Algonquin Gas Transmission Company (Algonquin) offers lower transportation rates to customers whose total maximum daily requirements do not exceed 10,000 MMBtu per day. Algonquin also offers different transportation service rates to customers depending on the rate schedule under which the customer was formerly served (e.g., prior to Order 636). A customer's former rate schedule varied depending on the type of service (sales for resale, transportation, etc.), the type of customer (local distribution company), and the pipeline company that delivered the gas to Algonquin. Algonquin's firm transportation reservation charges for these customers range from $7.18 per MMBtu to $16.46 per MMBtu. However, the corridor rate study compares general service rates for 1991 and 1994 to avoid tracking changes in rate schedules that are based on special circumstances.

Surcharges, which are included in the corridor rates, may also vary depending on customer characteristics. One notable example is the Gas Research Institute (GRI) demand surcharge. All monthly reservation rates in the corridor rate study include a $0.2180 per MMBtu GRI surcharge for customers with load factors over 50 percent and a $0.1340 per MMBtu GRI surcharge for customers with load factors of 50 percent or less. The difference in the GRI demand surcharge causes the reservation charge for 40-percent load factor rates to be slightly lower than that for the 100-percent load factor rates.

Development of One-Part Rates

The one-part rates are developed by summing the demand component converted to a unit basis, the usage rate, and the unit cost of fuel retained by the pipeline company. To convert to a unit basis, the reservation charge is divided by the product of the average number of days in a month times the load factor. In this way the one-part rate demonstrates the actual maximum unit cost of transporting gas on the selected pipelines for the customer load profile (Table E1).

Customer Load Profiles

The corridor rate study compares 1991 and 1994 rates for two customer load profiles. High-load-factor customers who tend to transport gas at a constant level throughout the year and low-load-factor customers who do not take gas at a constant rate throughout the year. The high-load-factor customers impose a daily demand on the system that is about equal to the average of their annual volume transported. For example, a customer who transports 365 MMBtu of gas per year will tend to transport about 1 MMBtu of gas per day. The industrial and electric utility sectors tend to be high-load-factor customers because their gas requirements are related to manufacturing needs as opposed to the demand for space heating.

The low-load-factor customers have a peak daily usage that far exceeds the average of their annual use. Residential and commercial sectors are generally low-load-factor customers because they depend on natural gas as a space-heating fuel. Their demand tends to fluctuate with weather temperature. Hence, the pipeline company must be prepared to meet these sectors' highest load requirement even though the maximum load may only occur a few times a year.

For this analysis a 100-percent load factor was used to represent the high-load-factor customers and a 40-percent load factor was used for low-load-factor customers. The 40-percent load factor assumes that the variable-use customers will impose a peak-day load on the system that is 2.5 times the customers' average daily requirements.

Transportation Routes and Pipeline Companies

Unit rates were developed for 21 transportation flow paths or routes. Each route represents the path gas must take on one or more pipelines to travel from the supply area to the point of use or market. A shipper may be able to choose between two or more routes to transport gas along any regional corridor. For example, a shipper wishing to transport gas on the Gulf Coast to Boston corridor may route his gas through Texas Eastern and Algonquin or route his gas through Tennessee Gas Pipeline Company.

The pipeline companies whose rate components are used to develop the corridor rates are:

Algonquin Gas Transmission Company
Altamont Gas Transmission (proposed)
ANR Pipeline Company
Colorado Interstate Gas Company
El Paso Natural Gas Company
Florida Gas Transmission Company
Iroquois Gas Transmission System, L.P.
Kern River Gas Transmission Company
Mojave Pipeline Company
NorAm Gas Transmission Company
Panhandle Eastern Pipe Line Company
Tennessee Gas Pipeline Company
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Transcontinental Gas Pipe Line Corporation
Trunkline Gas Company.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Northeast Region: Gulf Coast to Boston Transportation Corridor
(1994 dollars per million Btu)

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Route A						
TEXAS EASTERN (WLA-M3)						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	13.11	15.24	16.2	13.11	15.16	15.6
Usage Charge	0.43	0.15	-65.0	0.43	0.15	-65.0
Fuel Retention	4.0%	5.2%		4.0%	5.2%	
Total - Transportation Cost	0.93	0.75	-19.4	1.58	1.49	-5.7
Total - Delivered Cost of Gas	2.75	2.65	-3.7	3.40	3.39	-0.4
ALGONQUIN						
Gas Costs	2.75	2.65	-3.7	3.40	3.39	-0.4
Reservation Charge (1994 $/MMBtu-Mo.)	5.05	5.91	17.1	5.05	5.91	17.1
Usage Charge	0.17	0.02	-88.3	0.17	0.02	-88.3
Fuel Retention	0.6%	0.5%		0.6%	0.5%	
Total - Transportation Cost	$1.28	$0.98	-23.4	$2.19	$2.01	-8.2
Route B						
TENNESSEE (Z1-Z6)						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	7.76	26.77	244.9	7.76	26.69	243.8
Usage Charge	0.17	0.08	-53.4	0.17	0.08	-53.4
Fuel Retention	6.7%	7.8%		6.7%	7.8%	
Total - Transportation Cost	$0.55	$1.11	101.8	$0.93	$2.42	160.2

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Northeast Region: Appalachia to Boston Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Route A						
TEXAS EASTERN (M2-M3)						
Gas Costs	$2.18	$2.16	-0.7	$2.18	$2.16	-0.7
Reservation Charge (1994 $/MMBtu-Mo.)	8.25	10.35	25.4	8.25	10.27	24.4
Usage Charge	0.21	0.11	-48.7	0.21	0.11	-48.7
Fuel Retention	2.0%	2.9%		2.0%	2.9%	
Total - Transportation Cost	0.53	0.51	-3.8	0.94	1.02	8.5
Total - Delivered Cost of Gas	2.71	2.67	-1.3	3.12	3.18	2.0
ALGONQUIN						
Gas Costs	2.71	2.67	-1.3	3.12	3.18	2.0
Reservation Charge (1994 $/MMBtu-Mo.)	5.05	5.91	17.1	5.05	5.91	17.1
Usage Charge	0.17	0.02	-88.3	0.17	0.02	-88.3
Fuel Retention	0.6%	0.5%		0.6%	0.5%	
Total - Transportation Cost	$0.88	$0.74	-15.9	$1.55	$1.54	-0.6
Route B						
TENNESSEE (Z4 - Z6)						
Gas Costs	$2.18	$2.16	-0.7	$2.18	$2.16	-0.7
Reservation Charge (1994 $/MMBtu-Mo.)	5.83	12.74	118.5	5.83	12.66	117.0
Usage Charge	0.14	0.05	-64.1	0.14	0.05	-64.1
Fuel Retention	4.9%	2.2%		4.9%	2.2%	
Total - Transportation Cost	$0.44	$0.52	18.2	$0.73	$1.14	56.2

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Northeast Region: Canada to Boston Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	% Change
Route A						
IROQUIS (Zone 1)						
Gas Costs	$2.47	$2.20	-10.9	$2.47	$2.20	-10.93%
Reservation Charge (1994 $/MMBtu-Mo.)	10.01	13.57	35.5	10.01	13.49	34.69%
Usage Charge	0.14	0.01	-92.8	0.14	0.01	-92.82%
Fuel Retention		1.0%			1.0%	
Total - Transportation Cost	0.47	0.48	2.1	0.96	1.14	18.75%
Total - Delivered Cost of Gas	2.94	2.68	-8.8	3.43	3.34	-2.62%
TENNESSEE (Zone 5 - Zone 6)						
Gas Costs	2.94	2.68	-8.8	3.43	3.34	-2.62%
Reservation Charge (1994 $/MMBtu-Mo.)	6.82	12.34	80.9	6.82	12.34	80.94%
Usage Charge	0.09	0.04	-55.6	0.09	0.04	-55.56%
Fuel Retention	2.4%	2.1%		2.4%	2.1%	
Total - Transportation Cost	$0.85	$0.98	15.3	$1.69	$2.26	33.73%
Route B						
TENNESSEE (Niagra)						
Gas Costs	$2.47			$2.47		
Reservation Charge (1994 $/MMBtu-Mo.)	2.42			2.42		
Usage Charge	0.04			0.04		
Fuel Retention	1.2%			1.2%		
Total - Transportation Cost	0.15			0.27		
Total - Delivered Cost of Gas	2.62			2.74		
TENNESSEE (Niagra - Zone 6)						
Gas Costs	$2.62	$2.20	-15.9	$2.74	$2.20	-19.58%
Reservation Charge (1994 $/MMBtu-Mo.)	6.82	16.20	137.6	6.82	16.12	136.38%
Usage Charge	0.09	0.06	-30.0	0.09	0.06	-30.04%
Fuel Retention	2.4%	2.1%		2.4%	2.1%	
Total - Transportation Cost	$0.52	$0.64	23.1	$0.71	$1.43	101.41%

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Northeast Region: Gulf Coast to New York Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Route A						
TENNESSEE						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	7.76	22.89	194.9	7.76	22.81	193.8
Usage Charge	0.17	0.08	-53.4	0.17	0.08	-53.4
Fuel Retention	6.7%	7.0%		6.7%	7.0%	
Total - Transportation Cost	$0.55	$0.97	76.4	$0.93	$2.09	124.7
Route B						
TEXAS EASTERN						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	13.11	15.24	16.2	13.11	15.16	15.6
Usage Charge	0.43	0.15	-65.0	0.43	0.15	-65.0
Fuel Retention	4.0%	5.2%		4.0%	5.2%	
Total - Transportation Cost	$0.93	$0.75	-19.4	$1.58	$1.49	-5.7
Route C						
TRANSCO (Zone 3-Zone 6)						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	12.71	9.78	-23.1	12.71	9.70	-23.7
Usage Charge	0.30	0.16	-46.7	0.30	0.16	-46.7
Fuel Retention	7.4%	3.9%		7.4%	3.9%	
Total - Transportation Cost	$0.85	$0.56	-34.1	$1.48	$1.03	-30.4

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Northeast Region: Canada to New York Transportation Corridor
(1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
IROQUIS						
Gas Costs	$2.47	$2.20	-10.8	$2.47	$2.20	-10.8
Reservation Charge (1994 $/MMBtu-Mo.)	17.91	24.08	34.4	17.91	24.00	34.0
Usage Charge	0.21	0.02	-90.7	0.21	0.02	-90.7
Fuel Retention		1.0%			1.0%	
Total - Transportation Cost	$0.80	$0.83	3.7	$1.69	$2.01	18.9

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Southeast Region: Gulf Coast to Louisville Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
TEXAS GAS						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	8.49	13.14	54.8	8.49	13.06	53.8
Usage Charge	0.31	0.06	-80.7	0.31	0.06	-80.7
Fuel Retention	3.7%	2.3%		3.7%	2.3%	
Total - Transportation Cost	$0.66	$0.54	-18.2	$1.08	$1.18	9.3

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Southeast Region: Gulf Coast to Miami Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Florida Gas Transmission						
Gas Costs	$2.04	$1.90	-6.7	$2.04	$1.90	-6.7
Reservation Charge (1994 $/MMBtu-Mo.)	6.99	13.17	88.3	6.99	13.09	87.1
Usage Charge	0.11	0.07	-34.8	0.11	0.07	-34.8
Fuel Retention	2.3%	2.3%		2.3%	2.3%	
Total - Transportation Cost	$0.38	$0.55	44.7	$0.73	$1.19	63.0

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Southeast Region: Arkoma Basin to Louisville Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Noram (Arkla in 1991)						
Gas Costs	$1.67	$1.73	3.4	$1.67	$1.73	3.4
Reservation Charge (1994 $/MMBtu-Mo.)		6.32	N/A		6.24	N/A
Usage Charge	0.14	0.05	-64.1	0.14	0.05	-64.1
Fuel Retention	1.0%	1.7%		1.0%	1.7%	
Total - Transportation Cost	0.16	0.29	81.3	0.16	0.59	268.8
Total - Delivered Cost of Gas	1.83	2.02	10.2	1.83	2.32	26.6
Texas Gas (Z1 - Z4)						
Gas Costs	1.83	2.02	10.2	1.83	2.32	26.6
Reservation Charge (1994 $/MMBtu-Mo.)	8.04	12.09	50.4	8.04	12.09	50.4
Usage Charge	0.28	0.04	-85.6	0.28	0.04	-85.6
Fuel Retention	2.5%	2.3%		2.5%	2.3%	
Total - Transportation Cost	$0.75	$0.77	2.7	$1.15	$1.68	46.1

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Midwest Region: Gulf Coast to Detroit Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Route A						
TRUNKLINE						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	6.24	12.82	105.5	6.24	12.74	104.1
Usage Charge	0.16	0.05	-68.9	0.16	0.05	-68.9
Fuel Retention	1.5%	2.0%		1.5%	2.0%	
Total - Transportation Cost	0.39	0.51	30.8	0.70	1.13	61.4
Total - Delivered Cost of Gas	2.21	2.41	8.9	2.52	3.03	20.1
PANHANDLE EASTERN						
Gas Costs	2.21	2.41	8.9	2.52	3.03	20.1
Reservation Charge (1994 $/MMBtu-Mo.)	9.33	6.95	-25.5	9.33	6.95	-25.5
Usage Charge	0.23	0.03	-86.7	0.23	0.03	-86.7
Fuel Retention	5.1%	2.2%		5.1%	2.2%	
Total - Transportation Cost	$1.03	$0.82	-20.4	$1.82	$1.80	-1.1
Route B						
ANR						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	8.62	12.33	43.1	8.62	12.25	42.1
Usage Charge	0.39	0.05	-87.0	0.39	0.05	-87.0
Fuel Retention	2.0%	4.4%		2.0%	4.4%	
Total - Transportation Cost	$0.71	$0.54	-23.9	$1.13	$1.14	0.9
Route C						
TRUNKLINE (Field - Z2)						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	6.97	14.05	101.6	6.97	13.97	100.4
Usage Charge	0.17	0.05	-70.8	0.17	0.05	-70.8
Fuel Retention	1.8%	2.2%		1.8%	2.2%	
Total - Transportation Cost	$0.43	$0.55	27.9	$0.78	$1.24	59.0

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Central Region: Rocky Mountain to Denver Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Colorado Interstate Gas						
Gas Costs	$2.14	$1.62	-24.4	$2.14	$1.62	-24.4
Reservation Charge (1994 $/MMBtu-Mo.)	5.80	9.13	57.4	5.80	9.05	56.0
Usage Charge	0.13	0.04	-68.9	0.13	0.04	-68.9
Fuel Retention	3.0%	2.8%		3.0%	2.8%	
Total - Transportation Cost	$0.38	$0.39	2.6	$0.67	$0.83	23.9

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Central Region: Mid-Continent to Kansas City Transportation Corridor
(1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
PANHANDLE EASTERN						
Gas Costs	$1.67	$1.73	3.4	$1.67	$1.73	3.4
Reservation Charge (1994 $/MMBtu-Mo.)	5.13	11.34	120.8	5.13	11.26	119.2
Usage Charge	0.21	0.05	-76.7	0.21	0.05	-76.7
Fuel Retention	3.6%	3.0%		3.6%	3.0%	
Total - Transportation Cost	$0.44	$0.47	6.8	$0.70	$1.03	47.1

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

West Region: San Juan to Southern California Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
EL PASO NATURAL GAS						
Gas Costs	$1.65	$1.62	-1.9	$1.65	$1.62	-1.9
Reservation Charge (1994 $/MMBtu-Mo.)	6.30	9.39	49.0	6.30	9.31	47.6
Usage Charge	0.43	0.07	-83.7	0.43	0.07	-83.7
Fuel Retention	5.0%	5.0%		5.0%	5.0%	
Total - Transportation Cost	0.72	0.46	-36.1	1.03	0.92	-10.7
Total - Delivered Cost of Gas	2.37	2.08	-12.3	2.68	2.54	-5.3
MOJAVE						
Gas Costs	2.37	2.08	-12.3	2.68	2.54	-5.3
Reservation Charge (1994 $/MMBtu-Mo.)			N/A			N/A
Usage Charge	0.31	0.33	6.2	0.31	0.33	6.2
Fuel Retention	0.5%	0.5%		0.5%	0.5%	
Total - Transportation Cost	$1.04	$0.80	-23.1	$1.35	$1.26	-6.7

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

West Region: Canada to Southern California Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
ALTAMONT						
Gas Costs	$2.14	$1.75	-18.4	$2.14	$1.75	-18.4
Reservation Charge (1994 $/MMBtu-Mo.)			N/A			N/A
Usage Charge	0.55	0.51	-6.7	0.55	0.51	-6.7
Fuel Retention	1.4%	1.5%		1.4%	1.5%	
Total - Transportation Cost	0.58	0.54	-6.9	0.58	0.54	-6.9
Total - Delivered Cost of Gas	2.72	2.29	-15.9	2.72	2.29	-15.9
KERN RIVER						
Gas Costs	2.72	2.29	-15.9	2.72	2.29	-15.9
Reservation Charge (1994 $/MMBtu-Mo.)		23.77	N/A		23.68	N/A
Usage Charge	0.91	0.01	-98.4	0.91	0.01	-98.4
Fuel Retention	1.5%	1.0%		1.5%	1.0%	
Total - Transportation Cost	$1.53	$1.36	-11.1	$1.53	$2.52	64.7

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Southwest Region: Arkoma Basin to Little Rock Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
NORAM (formerly Arkla)						
Gas Costs	$1.67	$1.73	3.4	$1.67	$1.73	3.4
Reservation Charge (1994 $/MMBtu-Mo.)	4.75	6.32	33.1	4.75	6.24	31.3
Usage Charge	0.27	0.05	-81.3	0.27	0.05	-81.3
Fuel Retention	2.3%	1.7%		2.3%	1.7%	
Total - Transportation Cost	$0.46	$0.29	-37.0	$0.70	$0.59	-15.7

MMBtu = Million Btu. Mo. = Month.

Note: For 1994 rates, first reservation charge in each route includes a Gas Research Institute (GRI) surcharge of $0.2180 per MMBtu for 100 percent load factor rates and a $0.1340 per MMBtu GRI surcharge for 40 percent load factor rates.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **1991:** Florida Gas Transmission Company base rates—H. Zinder & Associates, *Summary of Rate Schedules of Natural Gas Pipeline Companies* (March 1991); Other rates—Foster Associates, *Competitive Profile of U.S. Interstate Pipeline Companies* (October 1991); **1994:** Kern River Gas Transmission Company base rates—Federal Energy Regulatory Commission Automated System for Tariff Retrieval (FASTR); Other rates—Foster Associates, *Competitive Profile of Natural Gas Services* (December 1994).

Appendix F

Companies with Electronic Tariffs on File at FERC

Appendix F

Companies with Electronic Tariffs on File at FERC

Respondents to FERC Form 2—Annual Report for Major Natural Gas Companies

1. Algonquin Gas Transmission Company
2. ANR Pipeline Company
3. Arkla Energy Resources Company
4. CNG Transmission Corporation
5. Colorado Interstate Gas Company
6. Columbia Gas Transmission Corporation
7. Columbia Gulf Transmission Company
8. East Tennessee Natural Gas Company
9. El Paso Natural Gas Company
10. Equitrans, Inc.
11. Florida Gas Transmission Company
12. Great Lakes Gas Transmission Limited Partnership
13. High Island Offshore System*
14. Iroquois Gas Transmission System, l. P.
15. Kern River Gas Transmission
16. KN Energy Inc.*
17. KN Interstate Gas Transmission
18. KN Wattenberg Transmission Ltd. Liability Co.*
19. Koch Gateway Pipeline Company
20. Michigan Gas Storage Company*
21. Midwestern Gas Transmission Co.
22. Mississippi River Transmission Corporation
23. Mojave Pipeline Company
24. National Fuel Gas Supply Corporation
25. Natural Gas Pipeline Company of America
26. Northern Border Pipeline Company
27. Northern Natural Gas Company
28. Northwest Alaskan Pipeline Company*
29. Northwest Pipeline corporation
30. Overthrust Pipeline Company*
31. Pacific Gas Transmission Company
32. Panhandle Eastern Pipe Line Company
33. Questar Pipeline Company
34. Sea Robin Pipeline Company*
35. Southern Natural Gas Company
36. Stingray Pipeline Company*
37. Tennessee Gas Pipeline Company
38. Texas Eastern Transmission Corporation
39. Texas Gas Transmission Corporation
40. Trailblazer Pipeline Company
41. Transcontinental Gas Pipe Line Corp.
42. Transwestern Pipeline Company
43. Trunkline Gas Company
44. U-T Offshore System*
45. Viking Gas Transmission Company
46. Williams Natural Gas Company
47. Williston Basin Interstate Pipeline Company
48. Wyoming Interstate Company Ltd.*

*These companies are not considered as major interstate pipelines. They file with the Federal Energy Regulatory Commission because they operate in offshore Louisiana/Texas Federal waters or they otherwise tie into or support other major interstate pipeline companies or services.

Respondents to FERC Form 2-A—Annual Report for Nonmajor Natural Gas Companies

1. Alabama-Tennessee Natural Gas Company
2. Algonquin LNG Inc. *
3. ANR Storage Company
4. Arkansas Oklahoma Gas Corporation
5. Arkansas Western Pipeline Company
6. Arkansas Western Gas Company *
7. Bear Creek Storage Company *
8. Black Marlin Pipeline Company *
9. Blue Lake Gas Storage Company
10. Bluefield Gas Company
11. Boundary Gas Company
12. Canyon Creek Compression Company
13. Caprock Pipeline Company
14. Carnegie Natural Gas Company
15. Centra Pipeline Minn. Inc.
16. Chandeleur Pipe Line Company
17. Columbia LNG Corporation *
18. DistriGas of Massachusetts Corporation
19. Eastern Shore Natural Gas Company
20. Freeport Interstate Pipeline Company
21. Gasdel Pipeline System Inc.
22. Gas Transport Inc.
23. Glacier Gas Company
24. Granite State Gas Transmission
25. Greely Gas Company *
26. Gulf States Transmission Company
27. Hampshire Gas Company
28. Honeoye Storage Corporation
29. Iowa-Illinois Gas & Electric *
30. Jackson Prairie Underground Storage Project
31. Jupiter Energy Corporation
32. KB Pipeline Company *
33. Kentucky-West Virginia Gas Company
34. Louisiana-Nevada Transit Company
35. Mid-Louisiana Gas Company
36. MIGC, Inc.
37. Mobile Bay Pipeline Company
38. Moraine Pipeline Company
39. National Pipeline Company
40. Nora Transmission Company
41. Oktex Pipeline Company
42. Orange & Rockland Utilities
43. Ozark Gas Transmission System
44. Pacific Interstate Offshore Inc.
45. Pacific Interstate Transmission Company *
46. Paiute Pipeline Company
47. Penn-Jersey Pipe Line Company
48. Penn-York Energy Corporation *
49. Pennsylvania & Southern Gas Company
50. Phillips Gas Pipeline Company
51. Point Arguello Natural Gas Line
52. Raton Gas Transmission Company
53. Richfield Gas Storage System
54. Riverside Pipeline Company, L. P.
55. Sabine Pipe Line Company *
56. South Georgia Natural Gas Company
57. Southern Energy Company (LNG) *
58. Southwest Gas Storage Company
59. Southwest Gas Transmission Company
60. Steuben Gas Storage Company
61. Sumas International Pipeline Inc.
62. Superior offshore Pipeline Company
63. TCP Gathering Company
64. Tarpon Transmission Company
65. Texas-0hio Pipeline, Inc.
66. Trunkline LNG Company *
67. Union Light, Heat & Power Company *
68. Valero Interstate Transmission Company *
69. West Texas Gas Inc.
70. Western Gas Interstate Company
71. Western Transmission Corporation
72. WestGas Interstate, Inc.

* Denotes nonmajor natural gas companies filing in Form No. 2 format.

Company Data Available Through the FERC FASTR System

1. Alabama-Tennessee Natural Gas Company
2. Algonquin Gas Transmission Company
3. Algonquin LNG, Inc.
4. ANR Pipeline Company
5. ANR Storage Company
6. Arkansas Western Pipeline Co.
7. Black Marlin Pipeline Company
8. Blue Dolphin Pipe Line Company
9. Blue Lake Gas Storage Company
10. Boundary Gas, Inc.
11. Canyon Creek Compression Company
12. Caprock Pipeline Company
13. Carnegie Natural Gas Company
14. Centra Pipelines Minnesota Inc.
15. Chandeleur Pipe Line Company
16. CNG Transmission Corporation
17. Colorado Interstate Gas Company
18. Columbia Gas Transmission Corporation
19. Columbia Gulf Transmission Company
20. Consolidated System LNG Company
21. Cove Point LNG Limited Partnership
22. Crossroads Pipeline Company
23. DistriGas Corporation
24. DistriGas Of Massachusetts Corporation
25. East Tennessee Natural Gas Company
26. Eastern Shore Natural Gas Company
27. El Paso Natural Gas Company
28. Equitrans, Inc.
29. Florida Gas Transmission Company
30. Gas Gathering Corporation
31. Gasdel Pipeline System, Inc.
32. Granite State Gas Transmission, Inc.
33. Great Lakes Gas Transmission Limited Partner
34. Gulf States Transmission Corporation
35. High Island Offshore System
36. Iroquois Gas Transmission System, L.P.
37. Jupiter Energy Corporation
38. K N Interstate Gas Transmission Co.
39. K N Wattenberg Transmission Limited Liability
40. Kentucky West Virginia Gas Company
41. Kern River Gas Transmission Company
42. Koch Gateway Pipeline Company
43. Michigan Consolidated Gas Company
44. Michigan Gas Storage Company
45. Mid Louisiana Gas Company
46. Midwest Gas Storage, Inc.
47. Midwestern Gas Transmission
48. MIGC, Inc.
49. Mississippi River Transmission Corporation
50. Mobile Bay Pipeline Company
51. Mojave Pipeline Company
52. Moraine Pipeline Company
53. National Fuel Gas Supply Corporation
54. Natural Gas Pipeline Company Of America
55. Nora Transmission Company
56. Noram Gas Transmission Company
57. North Penn Gas Company
58. Northern Border Pipeline Company
59. Northern Natural Gas Company
60. Northwest Pipeline Corporation
61. Oktex Pipeline Company
62. Overthrust Pipeline Company
63. Ozark Gas Transmission System
64. Pacific Gas Transmission Company
65. Pacific Interstate Offshore Company
66. Pacific Interstate Transmission Company
67. Pacific Offshore Pipeline Company
68. Paiute Pipeline Company
69. Panhandle Eastern Pipe Line Company
70. Penn-Jersey Pipe Line Co.
71. Penn-York Energy Corporation
72. Petal Gas Storage Company
73. Phillips Gas Pipeline Company
74. Questar Pipeline Company
75. Raton Gas Transmission Company
76. Richfield Gas Storage System
77. Riverside Pipeline Company, L. P.
78. Sabine Pipe Line Company
79. Sea Robin Pipeline Company
80. South Georgia Natural Gas Company
81. Southern Natural Gas Company
82. Southwest Gas Storage Company
83. Stingray Pipeline Company
84. Superior Offshore Pipeline Company
85. Tarpon Transmission Company
86. Tennessee Gas Pipeline Company
87. Texas Eastern Transmission Corporation
88. Texas Gas Pipe Line Corporation
89. Texas Gas Transmission Corporation
90. Texas-Ohio Pipeline, Inc.
91. The Inland Gas Company
92. Trailblazer Pipeline Company
93. Transcontinental Gas Pipe Line Corporation
94. Transwestern Pipeline Company
95. Trunkline Gas Company
96. Trunkline LNG Company
97. U-T Offshore System
98. Valero Interstate Transmission Company
99. Viking Gas Transmission Company
100. Washington Natural Gas Company
101. West Texas Gas, Inc.
102. Western Gas Interstate Company
103. Western Transmission Corporation
104. WestGas Interstate, Inc.
105. Williams Natural Gas Company
106. Williston Basin Interstate Pipeline Co.
107. Wyoming Interstate Company, Ltd.
108. Young Gas Storage Company, Ltd.

Glossary

Glossary

Affiliated Company: A company that is either directly or indirectly controlled and/or owned by another firm or holding company.

Alternative Fuel Capacity: The on-site availability of apparatus to burn fuels other than natural gas.

Annual Demand Charge: The charge to take "on demand" delivery based on annual volumes taken under the MFV rate design. Part of a two-part demand charge.

Billing Units: The basis used to convert costs into rates or fees. For reservation fees this may be the maximum daily quantity for service or the maximum annual quantity for service. For usage fees this may be the total annual throughput.

Blanket Certificate (Authority): Permission granted by the Federal Energy Regulatory Commission (FERC) for a certificate holder to engage in an activity (such as transportation service or sales) on a self-implementing or prior notice basis, as appropriate, without case-by-case approval from FERC.

Btu: Abbreviation for British thermal unit. The quantity of heat needed to raise the temperature of 1 pound of water by 1 degree Fahrenheit at a specified temperature and pressure (from 59 degrees Fahrenheit to 60 degrees Fahrenheit at an atmospheric pressure of 29.92 inches of mercury).

Certificated Capacity: The capability of a pipeline project to move gas volumes on a given day, based on a specific set of flowing parameters (operating pressures, temperature, efficiency, and fluid properties) for the pipeline system as stated in the dockets filed (and subsequently certified) in the application for the Certificate of Public Convenience and Necessity at the Federal Energy Regulatory Commission. Generally, the certificated capacity represents a level of service that can be maintained over an extended period of time and may not represent the maximum throughput capability of the system on any given day.

Coincidental Peak-Day Flow: The volume of gas that moves through a pipeline or section thereof or is delivered to a customer on the day of the year when the pipeline system handles the largest volume of gas.

Commodity Charge: The portion of a natural gas rate for bundled sales service based upon the volume actually purchased.

Contract Demand: The level of firm service in terms of the maximum daily and/or annual volumes of natural gas sold and/or moved by the pipeline company to the customer holding the contract. Failure of a pipeline company to provide service at the level of the contract demand specified in the contract can result in a liability for the pipeline company.

Daily Average Flow: The volume of gas that moves through a section of pipe determined by dividing the total annual volume of gas that moves through a section of pipe by 365 days. Volumes are expressed in million cubic feet per day measured at a pressure of 14.73 psia and a temperature of 60 degrees Fahrenheit. For pipes that operate with bidirectional flow, the volume used in computing the average daily flow rate is the volume associated with the direction of flowing gas on the peak day.

Deliverability: Refers to the volumes of natural gas which may be transferred at a designated point on the transportation network. The specific volume level is normally stated on a peak-day capability basis and is a function of facility (system) design which itself is premised upon actual or estimated market demand requirements. In the discussion that follows on network deliverability, that which pertains to pipeline service is predicated upon a summary measure of pipeline capacity at regional and/or State boundaries. Pipeline capacity is, in part, a function of the number of pipes, their diameter, compression, and operating pressure situated at the transfer point. Deliverability from storage represents a volume level that may be transferred to the pipeline network on a peak-day to supplement the pipeline capacity serving the regional market.

Deliverability (from storage): The output of gas from a storage reservoir, as expressed as a rate in thousand cubic feet (Mcf) per 24 hours, at a given total volume of gas in storage with a corresponding reservoir pressure and at a given flowing pressure at the wellhead.

Design Capacity: See certificated capacity. The design capacity of pipeline sections having bidirectional flow is the capacity associated with the direction of the flow observed on the peak day.

Federal Energy Regulatory Commission (FERC): The Federal agency with jurisdiction over interstate natural gas transportation and sale for resale rates, wholesale electric rates, hydroelectric licensing, oil pipeline rates, and gas pipeline certification.

Firm Service: Service offered to customers (regardless of class of service) under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses that permit unexpected interruption in case the supply to residential customers is threatened during an emergency.

Heating Degree Day: An index indicating the difference between 65 degrees Fahrenheit and the average temperature for a day, where the average temperature is the average of the day's high and low temperatures. If a day's average temperature were 45, there would be 20 degree days for the date. If the average temperature were above 65 degrees Fahrenheit, then the heating degree day would equal zero.

Interruptible Service: A sales volume or pipeline capacity made available to a customer without a guarantee for delivery. "Service on an interruptible basis" means that the capacity used to provide the service is subject to a prior claim by another customer or another class of service (18 CFR 284.9(a)(3)). Gas utilities may curtail service to their customers who have interruptible service contracts to adjust to seasonal shortfalls in supply or transmission plant capacity without incurring a liability.

Interstate Pipeline: A natural gas pipeline company that is engaged in the sale for resale or transportation, by pipeline, of natural gas across State boundaries, and is subject to the jurisdiction of FERC under the Natural Gas Act.

Intrastate Pipeline: A natural gas pipeline company engaged in the transportation, by pipeline, of natural gas not subject to the jurisdiction of FERC under the Natural Gas Act.

LDC: Local Distribution Company.

Load Factor: The ratio of average daily throughput volume to peak-day throughput volume or contracted volume (see definition of Maximum Daily Quantity). Low load factors are typically associated with small local distribution companies (LDC's) that serve residential and commercial customers with temperature-sensitive loads; high load factors are typically associated with larger LDC's that have a more diversified market or industrial and electric utility customers.

Native Gas: The volume of gas indigenous to the storage reservoir. It includes the total volume of unrecoverable gas and economically recoverable gas within the storage reservoir, which exerts a zero psig at the gauge pressure (psi) at which gas storage is started.

Noncoincidental Peak-Day Flow: The largest volume of gas delivered to a particular customer by a pipeline company in a single day during the year.

Markup: The average cost paid by a pipeline company customer to move a unit of gas.

Maximum Annual Quantity (MAQ): Annual allotment of capacity a customer has reserved on the system. This quantity usually takes into consideration seasonal variation in load and is therefore generally less that 365 times the Maximum Daily Quantity.

Maximum Daily Quantity (MDQ): Daily allotment of capacity a customer has reserved on the system . The quantity is usually based on peak requirements. The customer has the right to this capacity everyday of the year.

Maximum Interruptible Rate: The maximum allowed rate (price ceiling) for interruptible service. Generally, it equals the average unit cost to a firm customer with a 100-percent load factor.

Mileage-based Rate: These rates are also known as a distance-sensitive rates. Rates designed to reflect the variation in pipeline costs based on distance between receipt and delivery points. For instance, zoned rates are mileage-based.

Minimum Interruptible Rate: The minimum allowed rate (price floor) for interruptible service. Generally, it equals the variable cost of moving the gas.

Modified Fixed Variable: Fixed costs associated with the pipeline company's return on equity and associated income taxes are included in its volumetric charge, while all other fixed costs are recovered in the demand charge.

Off-Peak Service: Service made available on special schedules or contracts, but only for a specified part of the year during the off-peak periods.

Open-Access Transportation: The contract carriage delivery of nonsystem supply gas on a nondiscriminatory basis for a fee. Generally subject to transportation tariffs which are usually on an interruptible service basis on first-come, first-serve capacity usage.

Operator: The person or firm responsible for the day-to-day operation of a plant or facility.

Onsystem: Sales from the system supply of a local distribution company. Interstate pipeline companies have system supply and so they cannot have onsystem sales.

Optional Certificate (formerly known as Optional Expedited Certificate): In 1985, FERC issued Order 436, which instituted an optional procedure for construction projects whereby FERC does not assess the need for the project or evaluate competitive proposals if the pipeline company meets certain requirements, including assuming a majority of the risk of the project..

Peak-Day Demand Charge: The monthly charge to reserve "on-demand" delivery under a bundled sales service and is based on the amount of capacity reserved for the peak day under the MFV rate design. Part of a two-part demand charge.

Postage Stamp Rate: Flat rates charged for transportation service without regard to distance.

Rate Zone: This is a specified area where all customers pay the same price for the same level of service. Rate zones can cover large geographic regions over which gas may travel hundreds of miles.

Reservation Fee: A charge assessed based on the amount of capacity reserved on a daily basis. It is typically a monthly fee that does not vary based on throughput. Under SFV rate design, all fixed costs are allocated to the reservation component.

Section 311 Construction: Section 311 of the Natural Gas Policy Act of 1978 allows an interstate pipeline company to transport gas "on behalf of" any intrastate pipeline or local distribution company. Pipeline companies may expand or construct facilities used solely to enable this transportation service, subject to certain conditions and reporting requirements.

Service Agreement: An agreement between a natural gas company and a gas purchaser specifying the service to be rendered, area to be served, maximum obligation to deliver, delivery points, delivery pressure, applicable rate schedules by reference to the tariff, effective date and term, and identification of any prior agreements being superseded.

Storage (Reservoir) Capacity: The total volume of gas within a reservoir which exerts a pressure from 0 psig to the maximum or ultimate reservoir gauge pressure (psi). This should include all native gas (recoverable and unrecoverable), cushion (base) gas, and working (current) gas.

Straight Fixed Variable: All fixed costs are allocated to the reservation component and all variable costs to the usage component.

System Supply: Gas supplies purchased, owned, and sold by the supplier or local distribution company to the ultimate end user. System gas is subject to FERC or State tariff and is generally sold under long-term (contract) conditions.

Tariff: A compilation of all the effective rates, rate schedules, and general terms and conditions of service and forms of service agreements.

Throughput: Actual or estimated volume of natural gas that may be carried on a pipeline over a period of time.

Total Storage Capacity: The sum of working (current) gas capacity and the cushion (base) gas that must remain in the storage reservoir for purposes of pressure maintenance.

Usage Fee: A charge assessed for using reserved capacity on the pipeline system. Under SFV rate design, variable costs are allocated to the usage component.

Utilization Rate: Daily flow (throughput) as a percent of estimated capacity. For a segment of pipe, the average-day utilization rate equals the average-day flow divided by the estimated capacity.

Volumetric Rate Design: All costs are allocated to the commodity rate component.

Working (Current) Gas: The volume of gas in an underground storage reservoir in excess of total cushion (base) gas and which is available for delivery (withdrawal).