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.

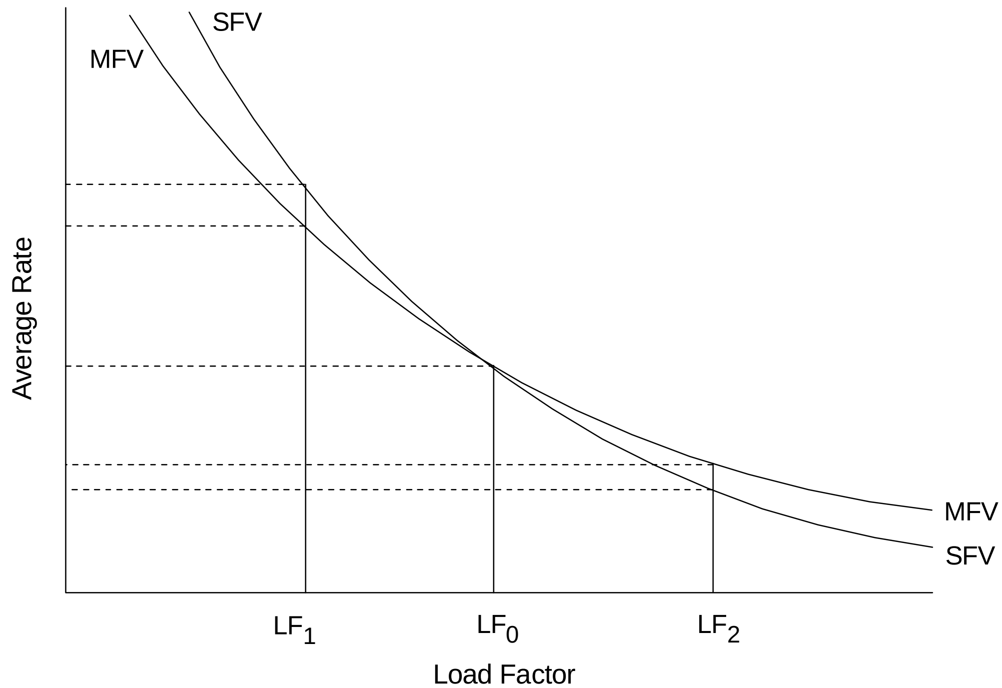
[8]In some cases, pipeline companies may have to forego recovery of some fixed costs by discounting costs from the maximum allowed rate in order to compete in the market.

[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.