4. Producers in Today's Competitive Market

Natural gas producers have faced many difficulties in the past decade as the industry has shifted to a more flexible, competitive system from a highly regulated one in which virtually all phases of their operations were circumscribed by regulation. Strong regulatory oversight had generated an environment in which business activity conformed to a relatively inflexible, traditional pattern. The creative energy of the producing firms generally was directed toward resolving the technical difficulties of discovery and extraction, rather than addressing business concerns such as availability of transportation capacity and promoting gas sales through aggressive marketing. The continuing transition to today's more competitive natural gas industry has presented numerous choices and challenges to producers. Their response during this period generally has shifted the industry to a more dynamic, efficient mode of operation.

Federal regulations affecting the producing industry changed in two very fundamental ways in the past 10 years: wellhead price decontrol and open access transportation.[74] Wellhead price decontrol, initiated in 1979 and completed in 1991, removed price constraints on interstate gas sales. Open access transportation, which was later enhanced by service unbundling, expanded the effective number of buyers in the wellhead market, thus transforming the structure from a monopsony to a highly competitive system. At the same time, the increase in potential buyers was mirrored in downstream markets as consumers suddenly enjoyed the benefits of access to a much broader set of suppliers, foreign as well as domestic. This led to intense sales competition among producers and with imported gas.

These changes resulted in the rapid evolution of producing firms as they changed contracting arrangements and practices in the field, as well as the nature of the firms themselves. The effects of regulatory change were exacerbated by the heightened competition caused by the drop in world oil prices and the rapid development of substantially improved exploration and production technology. Crude oil prices declined by 50 percent during the first half of 1986, from \$25.63 to \$12.83 per barrel.[75] The consequent competition from petroleum products strengthened the downward trend in average wellhead prices from the 3-year peak in 1982 to 1984 (after adjustment for inflation). Average wellhead gas prices (in constant 1995 dollars) fell 37 percent between 1985 and 1987 (Figure 31). The 9-year average from 1987 through 1995 of \$1.95 per thousand cubic feet (1995 dollars) is 43 percent below the 1985 level.[76]

The intense competition confronting producers as a result of open access transportation and the lower price environment created a need for new strategies to handle changing conditions effectively. Some of the responses were:

- **More use of short-term, market-oriented contracts and financial management tools to mitigate price risk.** Producers' participation in the New York Mercantile Exchange (NYMEX) futures market accounted for 20 percent of the total during the first quarter of 1996.

- **Changes in field practices to improve discovery and development operations.** Costs have been reduced by consolidating operations, improving efficiency and productivity, and extensively using new technology. As one example, average discovery field size in the onshore Gulf Coast for the most recent 5 years is more than 50 percent greater than the average for the 1980's.

- **Changes in corporate strategies to expand operations and capture economies of scale, attain a more secure position in gas markets, and position themselves for anticipated future conditions.** Producers have combined forces with companies that are experienced in other aspects of natural gas supply and energy marketing so as to expand their marketing operations and benefit from new business opportunities.

This chapter discusses these changes in the producing industry and examines general trends in its operations and productivity in the context of the extensive regulatory and market changes during the past decade. The chapter also examines the extent of industry competition in the lower 48 States, the degree of interregional competition, and the impact of foreign trade.

[74] *Open access transportation* in this chapter refers to the providing of transportation service as a separate service to customers on a first-come, first-served basis. Open access transportation is one of the "unbundled" services that had been provided by the pipeline companies on a combined basis, such as gas acquisition, storage, and load balancing. Open access transportation and unbundling thus eliminated the pipeline companies' role as the sole merchant-carriers of gas between producers and end-use markets.

[75] Based on composite refiner acquisition cost. Energy Information Administration, *Historical Monthly Energy Review: 1973–1992*, DOE/EIA-0035(73-92) (Washington, DC, August 1994), Table 9.1.

[76] All gas prices are from the Energy Information Administration's *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996).

Figure 31. Natural Gas Wellhead Prices, 1980-1995

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

Source: Energy Information Administration. **1980-1990:** *Annual Energy Review 1995* (July 1996). **1991-1995:** *Natural Gas Annual 1995* (November 1996).

A More Competitive Supply Industry and Wellhead Market

The regulatory shift of pipeline companies from owner-merchants to open-access service providers expanded the effective number of potential customers for most producers. The benefits of reaching more customers for their supplies, however, did not necessarily work as producers expected. When open access transportation was achieved, the difficulty of confronting the pipeline companies' strong market power in transportation was replaced by the difficulty of facing the competitive pressure from producers across North America. The resulting competition placed downward pressure on wellhead prices, which was exacerbated by supply increases from expanded domestic and foreign supplies. In effect, a new set of difficulties for producers replaced the earlier one.

A key feature of competitive markets is an effective pricing mechanism that provides signals prompting appropriate responses by market participants. Short-term, market-responsive contracts promote competitive behavior by reflecting the relative strength of supply or demand in a timely manner. This promotes efficiency in the allocation of industry resources into supplying gas to regional markets.

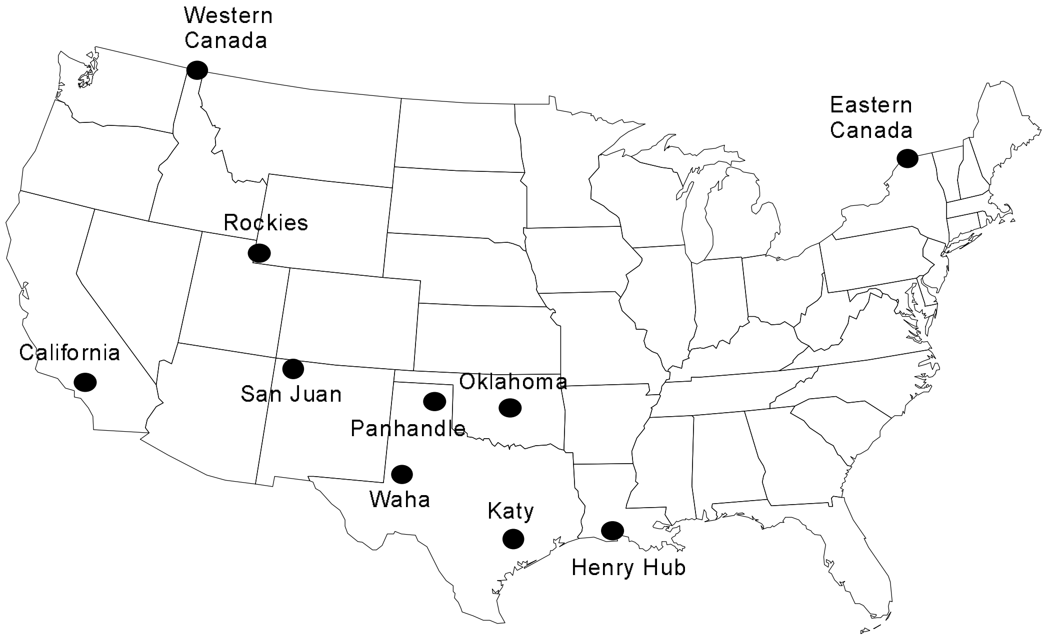
Regional gas prices serve as a signal for relative demand and supply conditions in each market. They also can indicate the degree of competition between markets. If gas markets are supported by an efficient infrastructure, consisting of the transmission network and institutional systems, regional demand and supply conditions will be interrelated. Market interrelatedness causes similar movements in prices although regional prices are not expected to be uniform.[77] The correspondence in price changes at different locations can be measured by the statistical correlation between prices.

An analysis of spot prices at major trading locations in the United States and Canada (Figure 32) shows wide variations in the relationships between markets.[78] Markets within the separate locations in the western, central, and eastern regions of the United States seem well interconnected. For example, the eastern markets (Katy in East Texas, Henry Hub in Louisiana, and Eastern Canada) have prices that are highly correlated (coefficients of 0.867 or more, Table 10). This tendency holds even for locations that are separated by

[77]For instance, prices in regions that are net importers of gas will tend to be higher than in regions that are net exporters. Nevertheless, to the extent that market institutions and the transmission infrastructure facilitate the movement of gas from one region to another, then supplies and demands in the different regions will be interrelated. Thus the prevailing price in one region will be affected by market conditions in other regions.

[78]Monthly spot price data (November 1993 through May 1996) for major North American trading locations were compiled and used to compute correlation coefficients, which range from 0.105 to 0.999 (Table 10). These figures ignore the simple 1.0 correlations for prices within each region.

Figure 32. Lower 48 States Map Showing Reference Locations for Price Correlation Analysis



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

Table 10. Correlations Among Regional Spot Market Natural Gas Prices

	CA	WC	Rocky	SJ	Waha	Pan	OK	Katy	HH	EC
Western Region										
California, Wheeling Ridge (CA)	1.00	0.96	0.97	0.98	0.69	0.66	0.67	0.32	0.29	0.11
Western Canada, Kingsgate (WC)	0.96	1.00	0.95	0.98	0.73	0.71	0.72	0.40	0.38	0.20
Rockies, Kern River (Rocky)	0.97	0.95	1.00	0.98	0.70	0.68	0.69	0.36	0.33	0.15
New Mexico, San Juan (SJ)	0.98	0.98	0.98	1.00	0.70	0.68	0.69	0.36	0.33	0.14
Central Region										
West Texas, Waha (Waha)	0.69	0.73	0.70	0.70	1.00	0.98	1.00	0.82	0.81	0.63
North Texas, Panhandle (Pan)	0.66	0.71	0.68	0.68	0.98	1.00	0.98	0.86	0.84	0.66
Oklahoma (OK)	0.67	0.72	0.69	0.69	1.00	0.98	1.00	0.82	0.81	0.63
Eastern Region										
East Texas, Katy (Katy)	0.32	0.40	0.36	0.36	0.82	0.86	0.82	1.00	0.99	0.87
So. Louisiana, Henry Hub (HH)	0.29	0.38	0.33	0.33	0.81	0.84	0.81	0.99	1.00	0.93
Eastern Canada, Waddington, NY (EC)	0.11	0.20	0.15	0.14	0.63	0.66	0.63	0.87	0.93	1.00

Note: The reported correlation coefficients were estimated based on monthly data over the period November 1993 through May 1996. Reference points for regional spot prices are shown in Figure 32.

Source: Energy Information Administration, Office of Oil and Gas. Derived from *Gas Daily's* reported monthly contract index prices, a measure of the weighted average cost of gas based on spot deals the week before the pipeline nomination period. In some cases, the analysis was based on pipeline-specific prices. These locations and the corresponding pipeline companies are: Western Canada, Pacific Gas Transmission; New Mexico, El Paso Natural Gas Company; Panhandle, Natural Gas Pipeline Company of America (NGPL); Oklahoma, El Paso Natural Gas Company; Katy, Transcontinental Gas Pipeline Corp. (Transco); and Eastern Canada, Iroquois Pipeline Company.

considerable distances, such as the Henry Hub and Eastern Canada which are in the eastern region (a 0.925 price correlation). Market pairs in the western regions (California, Western Canada, the Rockies, and New Mexico) and the central regions (Waha, Panhandle, and Oklahoma) correlate even more strongly within each region, with coefficients of 0.952 or more.

The interregional correlations indicate a lower degree of competition than that within regions. In particular, the price correlations between the markets in eastern and western regions are 0.40 or less. For example, the correlations of the price in California with other prices in the West show the influence of its relation with the major supply areas of Western Canada, the San Juan basin, and the Rocky Mountains. The California price correlations with the central regions are less, at 0.657 to 0.685, and are 0.321 and below for eastern locations, even Katy, Texas. Prices at the central regional markets generally correlate well with prices at all locations in both the eastern and western regions, being at least 0.633 in all cases.

The extent of price correlation between markets does not depend solely on distance. The prices at the Katy and Waha locations in Texas correlate strongly with each other at 0.822, which is consistent with the relatively slight east-west distance between these two hubs. However, despite their proximity and close price correlation, a fundamental difference between the two markets is apparent in the significant difference of correlations between the Katy hub and points west of Waha. Whereas the correlations for the Waha hub price and the western markets range from 0.685 to 0.733, the Katy hub has correlations of 0.397 or lower for the other four western points, indicating a lack of interrelatedness with those markets. The general division between eastern and western markets is exemplified by the low correlation coefficient of 0.201 between Western Canada and Eastern Canada.

Market integration has apparently improved in recent years, and regional clusters of markets across broad areas seem to be highly competitive, even between U.S. and Canadian markets. However, it is probably premature to conclude that a true North American market for natural gas has emerged in light of the seeming separation in competition between the eastern, central, and western regions. Besides the distance between markets, the degree of price correlation is affected by the nature of the infrastructure itself. These findings of generally competitive natural gas markets, although characterized by effective regional market separation, are consistent with the work of other analysts.[79] The market imperfections indicated by the price analysis are a longer term challenge that is expected to be mitigated or resolved with further refinements to the structure, operations, and institutions as the industry evolves.

Short-term market challenges are a market reality since prices often fluctuate, sometimes quite rapidly and dramatically, as demand and supply conditions shift. The unbundling of transmission services altered the basic structure of markets between producers and end users. As the production and transmission segments of the gas supply process have become more competitive and decentralized, the number of transactions has multiplied. The overall decentralization of functions imposes a need for coordination of industry segments. For example, gas must be produced when wanted, and transportation capacity connecting through to the ultimate consumer must be available. There is the possibility of “coordination failure” in the sequential purchase of the gas commodity and gas transportation. The consequence of such failure would be “episodes of price volatility and unused transportation.”[80] Gas market institutions have been designed to avoid such coordination failures, but price fluctuations may arise anyway as the system confronts extraordinary stress.[81]

In response to the difficulties that arose with increased competition, producing firms adopted new and better ways of doing business. Changes extended to field operations, commercial activities in the marketplace, and the structure of the firm itself. The success of these actions and the expansion of gas imports combined to satisfy a growing gas market despite the shift to lower prices.

Improved Operations: Contracting Changes

Natural gas contracts at the wellhead establish the terms for initial sale of produced gas. The key provisions address the

[79]See for example, Canadian National Energy Board, *Natural Gas Market Assessment: Price Convergence in North American Natural Gas Markets* (December 1995).

[80]Arthur De Vany and W. David Walls, “Open Access and the Emergence of a Competitive Natural Gas Market,” *Contemporary Economic Policy*, Vol. XII (April 1994), p. 92.

[81]The cold weather in January 1996 provides an example of short-term difficulties that cause variations in seasonal price patterns. Some transportation bottlenecks occurred that caused separation in the markets. Prices surged in Midwest and Northeast markets despite an apparent abundance of gas in areas such as Texas. At the same time, firm-service customers received their gas, so the markets appeared to operate as expected. It is expected that the economic opportunities posed by these bottlenecks and other industry performance inadequacies will motivate the industry to provide additional capability where needed, although lags in adjustment are expected.

two main issues for performance under the contract: volumes and pricing. Typical contracts before regulatory reform were long-term business arrangements of 15 to 20 years, particularly for sales under interstate jurisdiction. Long terms for contracts were often required of interstate pipeline companies in order to obtain a certificate of public convenience and necessity from the Federal Energy Regulatory Commission (FERC), or its predecessor, the Federal Power Commission, to expand service and connect new customers.

The impetus of FERC orders during the 1980's and the intense competitive pressure of drastically reduced petroleum product prices in 1986 created strong forces for change in the natural gas contracts of the time. Despite the availability of certain pricing options that would establish a more market-responsive contract, most contracts did not utilize them.[82] Discrepancies between contract prices and market prices were widespread in the mid-1980's. The increasingly competitive nature of the wellhead markets drove a need for commercial arrangements that were more flexible, so that participants could respond readily to changing market conditions.

Contracts today generally are short term, with flexible pricing and volumetric provisions. Even long-term contracts, which now extend for only 5 to 7 years, have considerable flexibility. These arrangements have the advantage of reducing transactions costs while maintaining an ongoing commercial relationship between buyer and seller. The increased flexibility allows transactions during the period of the contract to occur at prevailing market conditions. Thus, contract participants are not subject to performing under terms that were negotiated at the initiation of a contract many years earlier.

Price variation resulting from the flexible, market-based contracts raises uncertainty regarding the eventual prices that are realized under existing contracts. Price volatility made firms more aware of the need to manage increased price risk without entering again into long-term contracts with fixed terms. The need for a way to mitigate price risk led to the creation of a market for futures trading in natural gas, which opened for trading in April 1990. Prices determined on the futures market can be considered a clear indicator of prevailing market prices in order to establish prices as contracts are executed.

Futures trading meets the needs for a way to mitigate price risk and for a source of timely, reliable price information. However, futures trading does not eliminate price risk, and it is subject to risk in terms of expected volumes traded. If the actual volumes traded differ from the terms of the futures contract, the resulting profits and losses associated with any trade can be magnified. Nonetheless, futures trading has attracted traders of many types, including producers. The value of futures trading to producers can be inferred from their use of this trading option. Producers' participation in the natural gas futures market was 20 percent of the trading in the first quarter of 1996.

The response of the industry to the changing market seems to serve the industry and its customers well, but these institutional elements have not eliminated price variation. Price volatility has been a signature aspect of gas wellhead markets during recent years. In comparison with other commodities, natural gas prices remain extraordinarily volatile.

Cost Containment: Changes in Field Operations

Producers have made major strides in containing costs. Ways in which producers have improved their operations include redirecting their activities in the field and increasing productivity. Trends in costs and productivity show the impact of technology and improved efficiency on discovery and development activities.

Redirection of Producer Supply Activity

The reduced regulation of producers has allowed the market to establish competitive prices for gas supply activities at all stages in the delivery process. Prices distorted by regulation do not effectively direct industry resources to their most efficient applications.

The impact of drastically lower drilling levels caused by the falling prices after 1985 was mitigated by more efficient distribution of resources toward higher productivity locations and geologic settings. Drilling since the mid-1980's has been redirected toward those States that may be considered the more traditional gas suppliers: Texas, Louisiana, Kansas, Oklahoma, and New Mexico. Drilling also shifted to deeper, typically more productive strata. For example, the average depth of gas wells completed in the Permian Basin increased by 37.5 percent between 1987 and 1994. The movement into deeper locations has higher associated costs, but the prospects are expected to provide greater volumetric returns that reduce unit costs and enhance expected profitability.

[82]Only 48 percent of 1984 production from wells drilled after passage of the Natural Gas Policy Act (NGPA) in 1978 flowed under contracts with market-out provisions. Thirty percent of the 1984 production from post-NGPA wells flowed under contracts with neither market-out nor renegotiation clauses in effect. Energy Information Administration, *An Analysis of Natural Gas Contracts, Vol. III: Contract Provisions Covering Production of New Gas*, DOE/EIA-0505 (Washington, DC, May 1987), p. 32.

Producer activity also has been redirected to more consolidated field operations and the more efficient use of available proved reserves. The number of fields operated by large operators fell steadily from 1988 to 1994. The largest 10 producers in each year maintained their gas production levels (7.2 trillion cubic feet in 1994 compared with 7.1 trillion cubic feet in 1988), while the number of oil and gas fields operated by these firms declined by more than 50 percent.[83] Despite the large reduction in the number of active fields operated by large operators, gas reserves for these operators declined by only 9 percent. These trends indicate that the reserves per large operator has increased by consolidating operations and shedding marginal fields. The movement allowed operators to focus efforts and capture available economies of scale. Consolidation contrasts to the earlier approach of diversifying operations across many fields to lower overall investment risk. This new strategy may have been motivated and enabled by technological developments, such as three-dimensional (3D) seismic technology, that enhance operator knowledge of the reservoir.

Another change in producer activity has occurred in the area of inventory management. More efficient production operations have allowed operators to reduce their inventory of proved gas reserves. Reduced inventory lowers the financial cost of “carrying” the investment costs until recovery of initial capital costs is complete. The accelerated field production profiles associated with the reduced inventory produce larger expected present-value revenues for the project, which increases expected profitability. The faster cost recovery also improves the economic attractiveness of many investments because it diminishes the perceived overall risk of the projects stemming from price, cost, and other uncertainties.

Evidence of the more efficient use of reserves is seen in the decline in the level of proved reserves relative to production volumes over the past decade. The ratio of proved reserves to production for the lower 48 States declined to 8.5:1 in 1994 from more than 10:1 in the mid-1980's. Related to the decline in the reserves-to-production ratio is a reduction in the surplus wellhead gas productive capacity. Unused productive capacity fell by half from 1984 to 1993 when the surplus was 11.2 billion cubic feet per day. The surplus is estimated to decline further in 1995 and 1996 to 8.8 and 7.1 billion cubic feet per day, respectively, while the corresponding capacity utilization rates hit 85.7 and 88.3 percent.[84] This reduction in the relative size of reserve inventories and surplus capacity has raised concerns as a sign of increasing supply insecurity.[85] However, the general perception of abundant supplies and the lower unit costs have nonetheless yielded a steadily growing market for gas.

The substantial changes undertaken by producers to contain costs were predicated on regulatory reform of the transportation industry to move the larger volumes to market from new locations. Regulatory reform of the transmission industry, while not directly affecting producers, has been essential for the success of producers. Efficient use of the network and the capacity expansion response of the transmission companies allowed larger volumes to move to new markets.[86]

Increased Productivity and Lower Costs

Numerous measures show a definite increase in the productivity of various activities in the producing industry. One of the more striking examples is the average size of newly discovered gas fields. The traditional view of exploration is based on a discovery process model in which the largest volume prospects in each play are discovered more easily, hence earlier, so the trend in discovery size over a long period is expected to be downward. The historical performance of the industry tended to conform to this expectation until the 1980's. The average size of new-field discoveries for the onshore Gulf Coast serves as an illustrative example of the divergence between industry performance and the implications of the theoretical model. The average size surged in the late 1980's (Figure 33). The average size of gas fields discovered between 1990 and 1994 was more than 50 percent greater than the average field size discovered during the 1980's. Improvements in technology obviously have helped operators in the Gulf Coast to find better prospects or to provide a better initial estimate of proved reserves for the field.[87]

Newly completed wells also show better productive performance, as measured by produced volumes in the first producing year. Initial flow rate is a significant productivity

[83]These data are not differentiated between gas and oil fields.

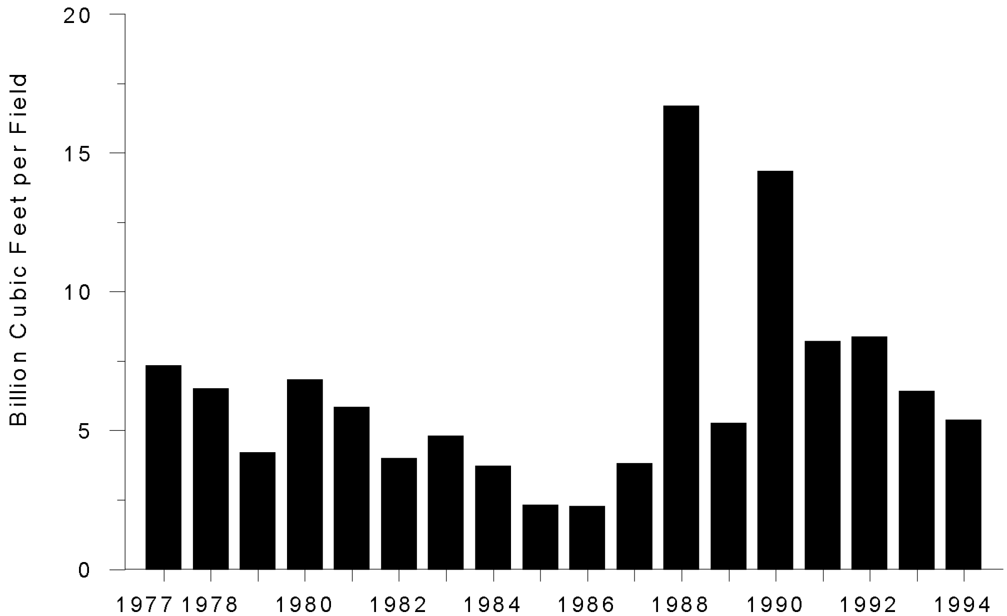
[84]Energy Information Administration, *Natural Gas Productive Capacity for the Lower 48 States 1984 Through 1996*, DOE/EIA-0524(96) (Washington, DC, February 1996).

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

[86]A recent, major event in the transmission sector is the development of a resale market for surplus capacity on either a short-term or long-term basis. This important development is discussed in Chapter 2 of this report.

[87]In addition to improving finding rates by increasing the yield from any given region, technology can improve aggregate finding rates by providing the opportunity to explore new areas, some of which may have significatnly larger discovery sizes. Data for disovered fields in the deep water region of the Gulf of Mexico serve as a prime example of this benefit from technology. See Chapter 1, “Key Issues: Offshore Deep Water Development” for a comparison of finding rates for deep water in the Gulf and other regions of the lower 48 States.

Figure 33. Average New Field Discovery Size in the Gulf Coast, 1977-1994



Note: The reported values are for nonassociated gas only. The reported values are based on the actual year the fields were discovered.
Source: Energy Information Administration (EIA), Office of Oil and Gas. Derived from Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves."

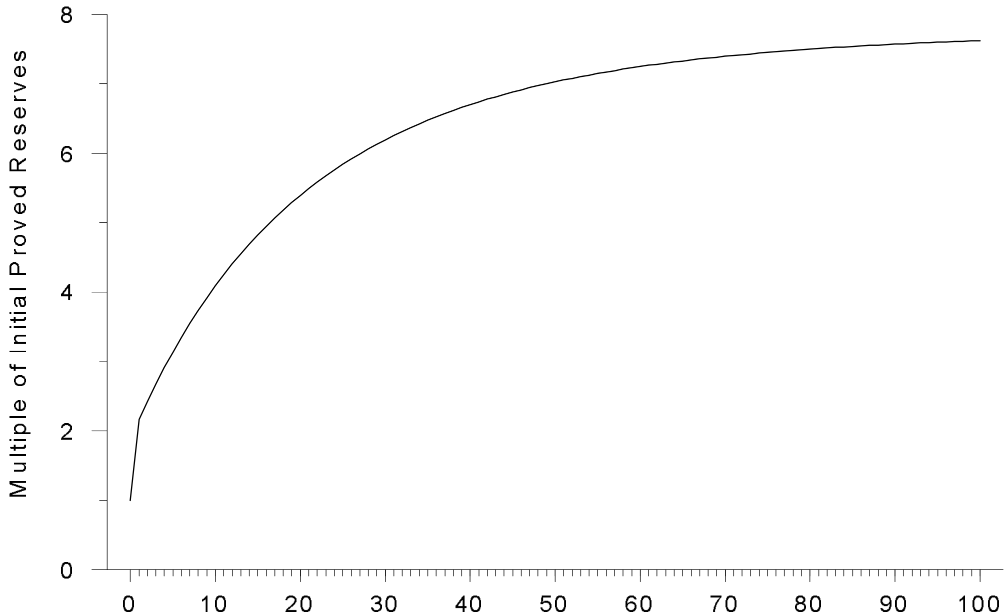
measure for two reasons. The present-value revenue from a well is typically increased with larger produced volumes in the early years, which improves the expected value of returns from new drilling. Secondly, if the new wells decline at a rate comparable to that of earlier wells, ultimate recovery from new wells will exceed that of older ones. Larger recovery volumes also enhance the economic attractiveness of drilling prospects.

Technology has enhanced operator performance in field development and increased the productivity of supply activities. The effects of improved field development and increased productivity can be seen in the gains for estimated ultimate recovery from the largest five gas fields in the lower 48 States. The estimated ultimate recovery from gas fields in the lower 48 States grows during the producing life of the field to 770 percent of the initial proved reserves estimate, on average. A stylized representation of this phenomenon shows a growth period of 100 years (Figure 34), during which recovery increases but at a steadily diminishing rate. The largest five fields were all discovered by 1947, so as mature fields they now should exhibit only modest growth in ultimate recovery. The estimated recovery from these five fields, however, rose rapidly after 1985 from a plateau in the 1981 to 1985 period (Figure 35).

Producers have had considerable success in containing costs, as indicated by recent trends in operating costs and lease equipment costs (all costs adjusted for inflation). Operating costs on average have dropped since the late 1980's. Average annual operating costs for all regions, depths, and well-production rates were $23,000 per well in 1995, after declining 3 percent between 1992 and 1995. The trend in operating costs is affected principally by recent changes in labor costs, which are a major influence on overall costs of gas well operations. Operating costs by region and depth show a consistent pattern of decline. Field equipment costs averaged over all regions, depths, and well-producing rates for the 1992 through 1995 period declined almost 10 percent, to $44,300 per well. Within this average change, cost changes by well-producing rate ranged from a decrease of 14 percent for wells flowing 1 million cubic feet per day to a decrease of 3 percent for wells flowing 10 million cubic feet per day.

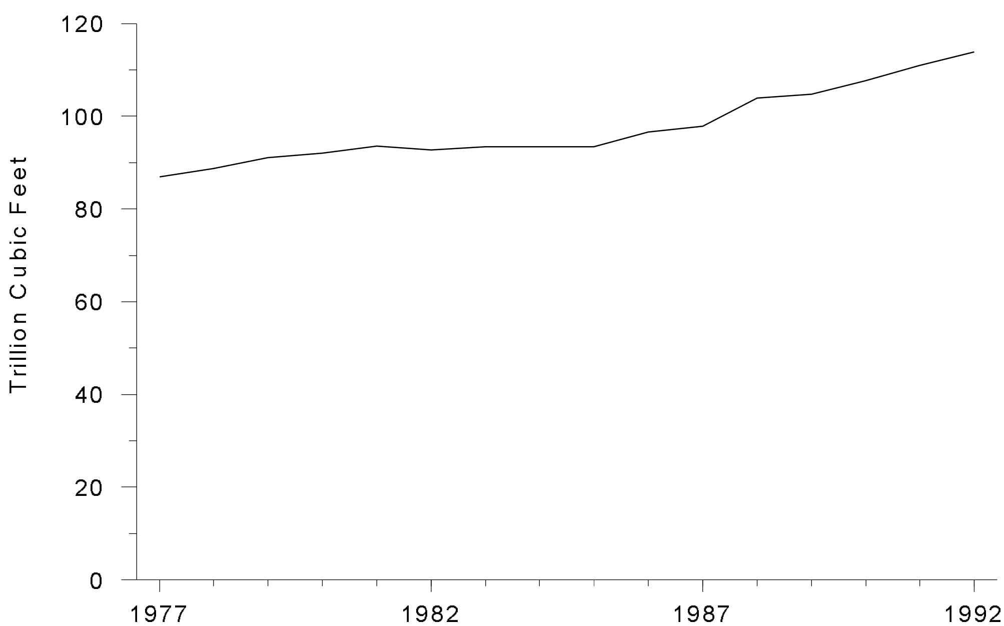
This evidence indicates the success of producers in meeting the need to improve basic operations and contain costs. As a result of the more competitive environment and lower prices, the industry has placed more reliance on innovation and technology, which has enhanced the industry's ability to find new reserves at higher productivity rates and lower unit costs. As new reserves "arrive" with ever-lower associated costs, these new gas supplies gain market share by bidding down prices. This is not a destabilizing factor within the industry, but it has maintained or increased downward pressure on wellhead prices throughout the lower 48 States.

Figure 34. Growth in Ultimate Field Recovery: Recovery as Multiple of Initial Proved Reserves for a Stylized Field



Source: Energy Information Administration, Office of Oil and Gas. Background information from *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy* (December 1990).

Figure 35. Growth in Ultimate Recovery for the Top Five Gas Fields in the Lower 48 States, 1977-1992



Source: Energy Information Administration, Office of Oil and Gas. Derived from data in Appendix B of *U.S. Crude Oil, Natural Gas, and Natural Gas Reserves*, various issues

Effects on Investment

The average natural gas wellhead price from 1993 through 1995 was $1.86 per thousand cubic feet (1995 dollars), which is 46 percent less than in 1985. The relatively low price has had two likely implications for investment. The industry has invested in those projects that have very short expected payback periods, such as onshore development projects, and those that have very large expected recovery volumes, such as deepwater prospects. The preference for short payback periods is reflected in the falloff in new field discovery volumes as a share of total discoveries since 1990.[88] The relative falloff in new field discoveries is curious in light of the well-recognized success of new search technology such as 3D seismic. The enhanced reliability of 3D seismic lowers drilling costs in a number of ways, but especially by avoiding dry hole costs. Avoiding dry hole costs is especially important for new field wildcat projects because of the lower average success rate for this type of drilling. A key advantage of development for investors, however, is that such projects have shorter payback periods, which lessens the uncertainty for a project due to exposure to industry events that might thwart cost recovery.

The greater volumes associated with projects such as those in deep water have a number of advantages. Production performance of wells, measured in terms of annual flow rates and ultimate recovery, generally is highly correlated with expected recovery for the field. The deep water regions offer prospects with the highest volumetric return in the lower 48 States. Deep water projects also exhibit relatively rapid recovery because of the physical properties in the region that favor high well flow rates. Accelerated field production provides a more favorable present value return. Despite enormous project costs, the expected discovery size in the deep water area can yield low unit costs of discovery and development. The strong interest in these projects, despite continued large financial risks, may be explained at least in part as a response to the downward cost spiral in the industry.

Corporate Strategies

Producing companies increasingly have pursued opportunities for new lines of business or ways to expand their firms in terms of both scale of operation and in related new businesses of strategic importance. Major concerns of producers include the downward price pressure presented by competition among domestic and foreign gas suppliers, and the low prices of competing fuels.

The composition of the industry is an important determinant of competition in the wellhead markets, which depends on both the number and relative size distribution of the firms in the industry. The presence of a few, relatively large firms in an industry frequently raises concerns about undue market power or unfair cost advantages accruing to the largest firms. A key feature of the gas-producing industry is that most of the producing firms are relatively small, privately held companies. The top 100 operators[89] in 1993 had an average wet gas production rate of 151.8 billion cubic feet per year, with the top 10 averaging 721.6 billion cubic feet. The 10 largest operators supplied 38 percent of wet gas production in 1994. This contrasts greatly with the average of 0.028 billion cubic feet reported for the year by the almost 90 percent of operators at the low end of the production range. However, the relatively unconcentrated nature of the industry overall and the fluid, dynamic transmission system are consistent with a finding that regional markets are not likely to be controlled by any one firm. Regarding possible cost advantages because of firm size, a recent study by the Energy Information Administration finds that independent firms have reserve replacement costs that, at less than $1 per thousand Btu, are almost equal to those of major producers.[90]

Producer Marketing Cooperatives

While producers continue as before to address the problems of discovery and extraction of natural gas from the ground, the growing competition in the wellhead market and the unbundling of services have caused producers to attend to gas marketing as never before. A number of producers have looked for opportunities to enhance their returns either by extending operations into other stages of the natural gas supply business such as storage or by forming strategic alliances that combine dissimilar activities in the vertically separated supply process to enhance their market position or capture economies of scale.

A number of firms have become concerned about what they perceive as their relatively limited market power (but not necessarily small size). A number of independent producers, dissatisfied with recent low prices and their impact on profitability, contend that they do not have the ability to compete with large marketers in the intensely competitive wholesale gas markets. Some argue that independents are at a disadvantage because they lack access to the breadth of

[88]New field discoveries for 1991 through 1993 were 10.2 percent of total discovery volumes, which is 34 percent below the 15.5 percent average for the 4 years ending in 1990. The 15.2 percent figure for 1994 is due mainly to the unusually large deep water fields, which raised the Federal offshore rate to 33 percent.

[89]Size is measured by production for the year 1994.

[90]Energy Information Administration, *Oil and Gas Development in the United States in the Early 1990s: An Expanded Role for Independent Producers*, DOE/EIA-0600 (Washington, DC, October 1995).

electronic information available to large marketers and that the large number of competing producers puts them at a competitive disadvantage in trying to sell their gas. In response to this situation, some independents have proposed the passage of legislation that would allow producers to form marketing cooperatives with limited exemption from Federal antitrust statutes (see box, p. 91).

Some expect that the formation of producer marketing cooperatives will provide considerable benefits to its members. Marketing cooperatives such as those in agriculture[91] provide various advantages, such as reducing transactions costs, providing joint sales promotions and advertising, and reducing costs to member firms through economies of large-scale purchasing and contracting for necessary goods and services. An additional advantage anticipated by proponents of gas producer cooperatives is sharing substantial amounts of timely information concerning market conditions. Further, such market combinations are expected to enhance the market position of independent producers given the expected large volume of produced gas managed by the cooperatives. Marketing cooperatives, according to this view, would provide market power, productivity and cost advantages, and overall efficiency gains.

The experience of other types of cooperatives indicates that it is not automatic that gas marketing cooperatives would be successful in influencing price to their members' advantage by reducing price volatility or avoiding low prices. Agricultural cooperatives do provide member farmers with certain costs savings and productivity enhancements. The record on the ability of cooperatives to support higher prices is much less clear. For example, agricultural commodities remain subject to cyclical variation in price despite the prevalence of "thousands of . . . cooperatives representing 2 million U.S. businesses with more than $82 billion in combined revenues."[92] Additionally, marketing arrangements similar to the proposed producer cooperatives have been used in Canada for years without much success in avoiding low prices or price volatility, despite somewhat less restrictive antitrust laws in Canada (see box, p. 92). The average wellhead price in Alberta was roughly 66 percent of the average wellhead price in the lower 48 States for the 1990 to 1994 period. The ability of Canadian producers to influence wellhead prices seems to have been uncertain and highly subject to market forces, so reliance on producer marketing cooperatives in the United States may not prove useful to independent producers in the long term.

Corporate Combinations

Alternative strategies for marketing gas include the formation of new corporate ventures. Corporate combinations include mergers of gas-producing firms horizontally, vertically, or with firms that supply other forms of energy. Corporate combinations are becoming more frequent, so clearly these alliances are perceived to offer various advantages to the involved firms.

Horizontal combinations are mergers between firms at the same level of the supply process, so the merged firms have roughly the same operational capabilities, although at a larger scale. Horizontal combinations tend to be attractive if the involved firms can increase their potential market power to offset the perceived market position of competitors or downstream firms such as marketers. Mergers of gas-producing firms have not occurred to any great extent perhaps because the resulting combined firms are not expected to attain the possible advantages to a significant degree. Horizontal merger plans also are subject to risk because they tend to attract more intense antitrust scrutiny than vertical or conglomerate mergers.

Vertical combinations provide the advantage of additional capabilities at different levels of the supply process. Vertical combinations serve to extend operations into other stages of the industry for short- or long-term profit potential or for gaining a strategic advantage. Producing firms also are expanding by forming conglomerate-type mergers, in which the participating firms are involved in the production or marketing of different energy forms. This movement has been given considerable momentum by recent Federal initiatives to reduce regulation and restructure the electric generation industry. The transformation of the electric generation industry may have the strongest impact on gas producers in the next few years, as electric generation companies are both customers and competitors for natural gas producers—virtually at the same time. Additionally, the similarities in marketing natural gas and electric power offer potential synergies for large marketers handling more than one fuel.

The extension of the producer's role into marketing, storage, and other supply activities may be viewed as a reaction to the unbundling of services previously offered in combination by the pipeline companies. The transportation operations of interstate transmission companies were augmented by load

[91]Marketing cooperatives for agricultural products are allowed under the Capper-Volstead Act (CVA) of 1922. The CVA provides limited antitrust exemption to associations of agricultural producers, permitting farmers to join and act as one farmer. However, cooperative marketing associations under CVA remain liable for antitrust law violations.

[92]Obie O'Brien, Director of Governmental Affairs for Apache Corporation, "Rx for America's Natural Gas Market," presentation to the California Independent Petroleum Association Annual Meeting (May 22, 1995).

Proposed Legislation to Allow Producer Marketing Cooperatives

A number of firms, most notably Apache Corp., have encouraged new legislation to rectify the reputed unfair market advantages enjoyed by gas marketers. The movement for new legislation resulted in the introduction by Reps. Lamar S. Smith (R-TX) and John Bryant (D-TX) of the "Natural Gas Competitiveness Act of 1995" (H.R. 2343) on September 14, 1995. This legislation, if passed and signed into law, would permit independent producers of natural gas to act together in associations "...in collectively producing, gathering, transporting, processing, storing, handling, and marketing in intrastate, interstate, and foreign commerce, natural gas (including natural gas liquids) produced in the United States." The association is prohibited from dealing in "natural gas (including natural gas liquids)" in an amount exceeding 20 percent of the volume of "natural gas (including natural gas liquids)" produced in the United States in the preceding calendar year.

The responsibility for policing associations' behavior for antitrust violations is delegated to the Attorney General of the United States. When the Attorney General believes that an association under the Act monopolizes or restrains trade to an extent that the price of natural gas is *unduly* enhanced, she may initiate administrative action. In addition, any person or State also may assert a claim against an association for violations of Federal antitrust law. At this point, the legislation is pending.

balancing, gas storage, local marketing (albeit limited), security of supply, and other services that enhanced the value of the delivered commodity to the consumer. The market power of interstate pipeline companies over transportation extended to these services, which precluded competition. The unbundling of nontransportation services provided potential competitors the opportunity to penetrate the separate markets for these services.

Over time, other firms saw the profit potential of separate, unbundled services. Many producers, however, were driven into marketing more by circumstances than by choice. The goals of conducting profit-making activities and developing needed capabilities to strengthen the overall market position of the firm led some producers initially to market their own gas. As competition in gas marketing increased, good economic performance in this area became more difficult.

Marketing difficulties have caused some producers to merge with marketing firms, thus resulting in a combination of activities. For example, Chevron Corporation and NGC Corporation, Houston, announced their intent to merge, thus forming the largest gas and natural gas liquids (NGL) marketer in North America, with sales exceeding 10 billion cubic feet per day. The merged company would be the largest NGL processor and marketer in North America, with volumes of 140,000 and 470,000 barrels per day, respectively. The expected advantages of the combination include lower unit costs for NGC and "new opportunities" because of its larger scale of operations. NGC will have the ability to offer a set of energy commodities including natural gas, gas liquids, electricity, and crude oil to customers. Other examples of corporate combinations involving producers include: Shell Oil Company, a unit of Royal Dutch Shell Group, which has joined forces with Tejas Gas Corporation; Mobil Corporation and PanEnergy who have agreed to market gas jointly;[93] and Tenneco Energy and El Paso Energy.[94]

The marketer segment of the gas industry has experienced significant changes, which has important implications for the future of gas producers in light of the key position in the supply process that is occupied by marketers. Gas marketing has undergone dramatic consolidation. The top five marketers for 1995 moved 27.7 billion cubic feet per day, which is more than half the 46.2 billion cubic feet per day moved by the top 20 in 1993. Even new entrants can be sizeable competitors. CNG Energy Services and PennUnion, two companies that did not exist in 1994, were among the top 25 in 1995. Another significant feature of the top 25 marketers in 1995 is that no independent marketer is included. All of the top 25 are either producer or pipeline affiliates or gathering-processing-marketing companies. The trend of the past 3 years is expected to be continuing in 1996. Despite the shift to a core group of large marketers, smaller companies are expected to remain as specialized firms that operate in a certain geographic area or provide particular services.

The industry of the future does not require producer-marketer mergers across the industry, but it is one reaction to new industry realities. The evolution of the industry has created a complex environment in which the tradeoff between risk and reward is not readily grasped. In fact, no single strategy is likely to be appropriate for all, or even most, firms.

[93]"Front Burner: Tired of Phone Wars? Get Ready for a Fight to Sell Natural Gas," *Wall Street Journal* (April 16, 1996), p. 1.

[94]"El Paso to acquire Tenneco for $4 billion" *Gas Market Week* (June 24, 1996), p. 1.

Canadian Natural Gas Marketing Arrangements

The Canadian natural gas industry has relied for some time on a marketing system that has strong similarities to the proposed U.S. producer cooperatives. The Canadian system includes aggregators who purchase gas from several producers under netback-priced gas contracts. The price paid to the producer on a netback basis is determined by the resale price downstream. Under the Natural Gas Marketing Act (NGMA) enacted by Alberta in 1985,* producer interests in Alberta are protected by prohibiting an aggregator selling gas under a netback agreement from removing gas from Alberta or delivering it in Alberta for resale to another person, unless there has been a finding of producer support. Thus, producers retain an active role in the decision to execute a sale for resale on their behalf, which in practice is similar to the proposed role for U.S. producer cooperatives. This differs substantially from U.S. marketers, who simply purchase the gas outright from producers and then control its subsequent disposition. A second similarity to proposed U.S. cooperatives is that Canadian aggregators and producers have an opportunity to share information on the pending sale and current market conditions. This information-sharing reaches all parties and is facilitated by the information sessions.

Producer support is determined by the aggregators by a system of voting by ballots. Ballots consist of a question answerable by a "yes" or "no" response only. Prior to distribution of the ballots, aggregators often conduct information sessions to brief producers on their marketing efforts and to prompt them to accept the proposed contracts. The Bureau of Competition Policy (BCP) has evidenced concern that the information sessions are conducted circumspectly, and that anti-competitive activities or agreements are avoided. For example, producers should not agree to refrain from competition with the aggregators in certain markets; aggregators cannot encourage production curtailments to influence prices upward; and sensitive market information such as pricing strategies cannot be exchanged.

Canadian antitrust law, while similar to that of the United States, differs in the nature of prohibited actions. The major antitrust law in Canada is the Competition Act, which is intended to "remove impediments to free and open competition and is designed to promote efficiency at home and to expand opportunities for Canadian business abroad."** In pursuing anti-competitive behavior, the BCP gives top priority to behavior between competitors. Key provisions of the Act related to these offenses are:

- Section 45 — *Conspiracy* requires two elements: (1) existence of some degree of market power, and (2) existence of behavior likely to injure competition.
- Section 47 — *Bid-rigging*: one or more bidders refrain from submitting bids, or arranged bids are submitted. Bid-rigging is a *per se* offense.
- Section 61 — *Price maintenance*: an attempt to influence prices upward or discourage price reductions by agreement, threat, promise or like means.

An important activity promoting corporate compliance is the issuance of advisory opinions to firms concerning a proposed business plan or practice. In 1990, the BCP reviewed an instance in which an aggregator, six producers, and a local distribution company (LDC) were to negotiate a sales contract. The issues considered were whether the aggregator may hold meetings with the producers to discuss pricing strategy and whether two representatives of the producers may participate directly in the negotiations with the LDC. The BCP determined that these producers could not influence the price upward because they were a small portion of the industry-wide supply and a small portion of supply to the LDC, so the conspiracy and price maintenance provisions of the Act did not apply.

The 1990 opinion exhibits an interesting difference in Canadian antitrust law compared with that of the United States. Bid-rigging is illegal under Section 47 of the Competition Act, unless the "...situation is known to the person calling tenders..." Although "bid-rigging is a *per se* offence in that no lessening of competition need be demonstrated," disclosure of the activity seems sufficient to remove culpability. The LDC was aware that the six producers were submitting a joint bid, so the bid-rigging provision did not apply. This is in contrast to U.S. antitrust case law, which generally holds that direct price-fixing agreements are *per se* violations of the law.

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*British Columbia has similar legislation. British Columbia and Alberta together accounted for over 94 percent of 1994 Canadian natural gas production.

**Harry Chandler, Bureau of Competition Policy, *Competition Law Issues in the Upstream Oil and Gas Industry*, Notes for An Address to the Canadian Petroleum Law Foundation (Jasper, Alberta, June 11, 1992).

Combinations such as those pursued by major producers with large marketing firms may reflect a changing outlook on longer-term strategic planning by the firm. Other corporate developments in the gas supply industry include firms that provide services that previously were internal to the transmission companies or are now internal to other large firms, such as the information activities of large gas marketers. The unbundling of transmission company services opened a myriad of commercial possibilities. Gas marketers arose to serve as gas aggregators and to focus on aggressive marketing. Storage operators provide a valued service to the markets. Market hubs evolved as an efficient combination of services offered in a particular locale. The combination of storage, load balancing, and physical interconnections for transportation and transfers of gas between firms provides important services and reduces the administrative burden for participating firms.

One already identified need, according to some firms, is for more reliable, timely information regarding regional market conditions. This has led to the creation of information services that provide data about sales at various locales on a daily basis.[95] Other developments in this area include companies with refined information services that provide data on a real-time basis which are of comparable quality to the information collection and dissemination activities that are internal to the large marketing companies. This approach captures economies of scale and allows the cost of personnel, capital, and required expertise to be shared among the customers. This type of information service is provided to producing companies on a subscription basis.

Foreign Trade: A Challenge to Domestic Producers

Foreign trade is an important aspect of the U.S. natural gas industry and markets, especially with the stimulus from regulatory reform initiated in the mid-1980's. The U.S. Government has undertaken a number of policy actions directly related to foreign trade since the mid-1980's including the Canadian Free Trade Agreement (CFTA) and the North American Free Trade Agreement (NAFTA). The ratification of these treaties marked the endorsement of free trade principles. The practical significance of the treaties arguably has been modest because of already existing regulation that promoted free trade. The CFTA and NAFTA nonetheless are important actions that validate the free trade process. Further, these treaties may serve a key role in preventing any retreat or diversion from free trade principles in the future.

Foreign natural gas supplies are an attractive option for many U.S. consumers. Imports comprised almost 13 percent of U.S. consumption in 1995. Foreign gas producers, especially those in Canada, provide strong competition for U.S. producers, as evidenced by the large increase in natural gas import volumes since the mid-1980's (Figure 36). The vast share of U.S. natural gas imports is from Canada—over 97 percent from 1990 through 1995. Purchases of Canadian gas reached an all-time high of 2.82 trillion cubic feet in 1995. Other foreign supplies come from Mexico via pipeline and from Algeria as liquefied natural gas (LNG) in special tankers. Limitations on available supplies or transportation have kept other imports at a combined average of 40 billion cubic feet per year since the mid-1980's.

Increased Supply from Canada

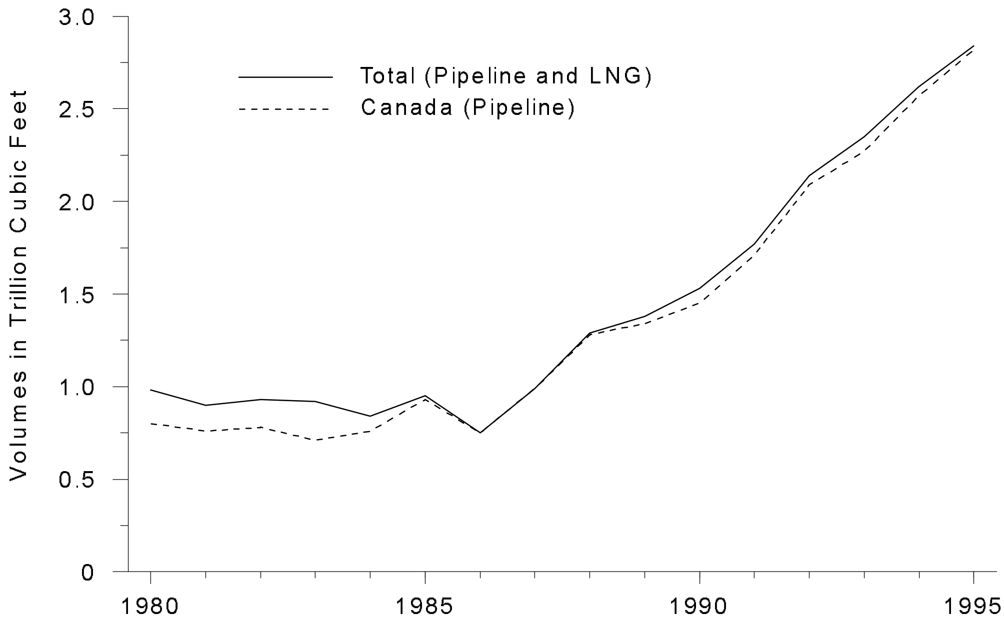
Canadian exports to the United States since the mid-1980's were stimulated by regulatory reform in Canada (see box, p. 95). The Canadian government had moved to market-based prices for exports in 1985, and it virtually removed regulatory restrictions regarding approval of volumes for export in 1987. While regulatory reform provided the opportunity for export expansion, the realization of this potential required physical and economic characteristics that supported increased production and sales. Growing sales to the United States from Canada have benefited from a number of competitive advantages.

One contributing factor was the large stock of Canadian proved reserves relative to production that was present in the mid-1980's. Regulations pertaining to foreign sales in the 1980's imposed large reserve requirements as a condition of approval. This resulted in a large reserves-to-production ratio, which was close to 30:1 for the Western Canada Sedimentary Basin during the first half of the 1980's,[96] compared with the U.S. level of roughly 10:1 (Figure 37). When regulatory reform opened the way for increased exports, the relatively large gas inventory provided readily available supplies. It was also a relatively low-cost source of gas because the discovery costs of this gas already had been accounted for, and expanded sales depended only on the addition of development wells, which tend to cost less than exploratory wells.

[95] Examples include selected spot prices as published by Pasha Publications, Inc. in the *Gas Daily* and by Dow Jones Telerate Energy Services.

[96] Data for the Western Canada Sedimentary Basin (WCSB) are used as representative of Canadian production potential because the region has been the source of roughly 99 percent of total production during the period of discussion. The WCSB is contained largely in British Columbia, Alberta, and Saskatchewan.

Figure 36. U.S. Imports of Natural Gas: Total and from Canada, 1980-1995



LNG = Liquefied natural gas.

Source: Energy Information Administration, Office of Oil and Gas. **1980-1989**: *Natural Gas Monthly* (August 1995). **1990-1995:** *Natural Gas Monthly* (November 1996).

Certain characteristics of the Canadian industry provide further competitive advantages. The average gas flow rate per gas well in Canada has grown almost continuously since 1986 to a level of roughly 330 thousand cubic feet per day in 1994. This flow rate dwarfs the 1994 U.S. daily average of roughly 180 to 190 thousand cubic feet from 1990 to 1994. Operating costs as a fraction of gross revenue in 1994 were at their lowest level since 1987. While expenditures on operating costs have grown gradually during the past decade, the relative decline in operating costs has been driven by the growth in Canadian production, which increased roughly 50 percent from 3.5 trillion cubic feet in 1990 to 5.2 trillion cubic feet in 1994.

Canadian gas exports also benefited from changes in the relative value of the currency. U.S. imports are generally priced in terms of U.S. dollars, so changing currency values are not reflected in the purchase prices to the U.S. consumer. However, the fall in the value of the Canadian dollar since 1990 has enhanced the monetary value to Canadian producers of gas sold to the United States. The change in the exchange rate alone increased the monetary value of gas sold to the United States by almost 20 percent between 1991 and 1995. The currency change in conjunction with market conditions resulted in a 1995 Western Canadian wellhead price of $1.38 (Canadian dollars) per thousand cubic feet, comparable to the $1.36 in 1991. In the United States, the 1995 price of $1.55 per thousand cubic feet was more than 5 percent below the 1991 price of $1.61 (nominal dollars).

Exchange rate fluctuations do not necessarily favor either country consistently, so they are not a reliable competitive advantage for Canadian producers. Further, it is the fluctuations rather than any relative value of the currencies that are problematic, because unanticipated shifts in the exchange rate thwart the intentions of parties to the crossborder trade contracts. Even relatively steady border prices measured in U.S. dollars may vary considerably when measured in Canadian dollars. If the currencies become unstable, the resulting uncertainty may hamper continued trade.

Additional price risk has arisen because of increased location risk between Alberta wellhead prices and prices in the established futures trading markets. Futures trading is used increasingly as a hedge to mitigate price risk and as a benchmark to determine sales prices under flexibly priced contracts. The location risk has increased, however, as the futures price series have failed to correlate well between eastern and western markets. This factor, if left unchecked, could impede export sales of Canadian gas, but this situation

Canadian Regulatory Changes

The North American gas market is more interrelated today than it was just a few years ago. In 1984, 755 billion cubic feet of natural gas was exported by Canada to the United States, by 17 exporters. This volume has grown steadily to a level of 2,816 billion cubic feet in 1995, which was shipped by 205 exporters. The emergence of free markets across North America has stimulated strong industry performance that supports the growth of markets in the United States and Canada.

Major changes in regulation and legislation governing the Canadian gas market since 1983 have directly contributed to Canada's strong presence in the U.S. gas market. During the early 1980's, the Canadian gas market was characterized by oversupply. The combination of falling demand and increasing supply led to the emergence of excess productive capability. This problem of oversupply was exacerbated by the high reserves-to-production ratio requirement for export approval, which began in the late 1970's during widespread government intervention in Canadian gas markets. The Volume Related Incentive Pricing Program, introduced in 1983, allowed exporters to sell quantities of natural gas in excess of an established base level at an incentive price. The incentive prices, often tied to petroleum prices as well as the Weighted Average Cost of Gas (WACOG), proved an impediment to growth of gas sales to the United States. Subsequently, several policy changes made Canadian gas more competitive in export markets.

- The Agreement on Natural Gas Markets and Prices in 1985 changed the pricing policy from government- administered pricing to market-oriented pricing. This agreement made possible:
  - Direct sales negotiated between producers, distributors, and large industrial users
  - Competitive marketing programs allowing distributors to offer discounts
  - A review of the role of interprovincial and international pipeline companies
  - Changes in export pricing policy allowing for negotiation to make Canadian gas more competitive in U.S. markets
  - Short-term export orders of up to 2 years without volume restrictions.

- The "market-based procedure" for determining the surplus natural gas available for export, adopted in 1987, replaced the previous reserves-to-production (R/P) ratio procedure. The R/P ratio procedure required relatively high R/P ratios in order to establish that gas for export was surplus to foreseeable Canadian requirements. This restriction limited production to a relatively low rate, which in turn constrained the amount available for export. Changes brought about by this procedure included a requirement that export sales contracts contain provisions permitting adjustments to reflect changing market conditions, and a provision to ensure that export arrangements provide a reasonable assurance that the gas contracted for would be taken.

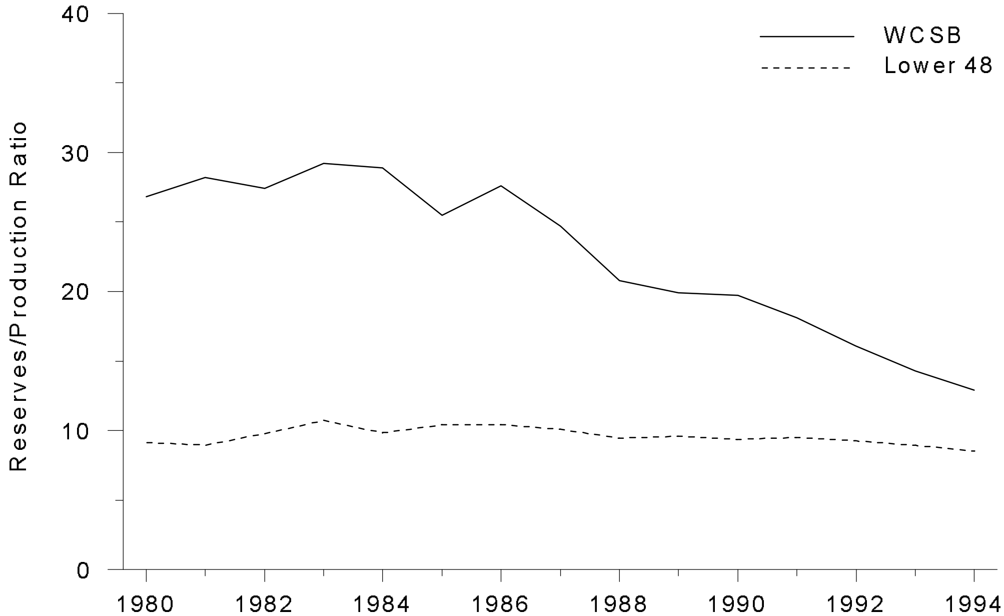
- The U.S.-Canadian Free Trade Agreement of 1988 (CFTA) prohibited most import/export restrictions on energy products. The agreement eliminated import/export taxes, removed bilateral tariffs, and ended price discrimination. However, the agreement did allow either country to restrict exports in cases of supply shortage, to maintain a domestic price stabilization program, or to enact resource conservation measures. Subsidies and incentives for natural gas development were allowed to continue.

- In March 1993, the National Energy Board decided, after public hearing, that it would no longer include benefit-cost analysis in determining whether proposed natural gas exports were in the public interest. This facilitated sales of Canadian gas exported under short-term orders. There were 151 short-term import/export orders issued during 1990.

- The North American Free Trade Agreement (NAFTA), enacted at the end of 1993, created the largest trading block in the world. Since most trade barriers that existed between the United States and Canada were lifted by the U.S.-Canadian Free Trade Agreement of 1988, NAFTA did not produce significant regulatory changes between the two countries.

- Effective November 1, 1993, the National Energy Board issued two orders ending restrictions of natural gas exports to northern California. The original orders, issued in 1992, restricted exports because of a dispute over short-term sales replacing long-term sales. The shift to short-term sales reflects a recognition that a free market framework is dominant in North American gas trade.

Figure 37. Reserves-to-Production Ratios, United States and Canada, 1980-1994



Note: WCSB is the Western Canadian Sedimentary Basin, which is contained primarily in the Canadian provinces of British Columbia, Alberta, and Saskatchewan. It is the source of about 99 percent of Canadian production.

Source: Energy Information Administration, Office of Oil and Gas. **Lower 48 States:** derived from data published in *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, various issues. **WCSB:** derived from data published in *Statistical Handbook*, Canadian Association of Petroleum Producers (July 1995).

has led to the creation of two futures contract markets for delivery in West Texas.[97] Trading at the Waha Hub market center and the Permian Pool area is expected to lessen some of the location risk for Albertan traders because of the better correlation in price movements between these western markets. In addition, a new futures contract for delivery in Alberta, Canada, began trading in September 1996. This newest contract is expected to correlate more closely with Canadian prices and the U.S. markets served by Canadian natural gas. While location risk can be a significant factor affecting trade, it does not appear to have been a major barrier to trade between the two countries. Future Canadian imports are expected to show continued expansion, although it is unlikely to grow at levels comparable to that observed since 1990.

[97]The Kansas City Board of Trade futures contract was established in August 1995 for delivery at the Waha Hub in West Texas. The New York Mercantile Exchange (NYMEX) opened a new contract in July 1996 for delivery through the Permian Pool, also in West Texas. In late September 1996, NYMEX opened another new contract for delivery in Alberta, Canada.

Potential U.S. Gas Market in Mexico

The most far-reaching regulatory actions by the U.S. and Canadian governments regarding crossborder gas trade occurred by the end of 1987, with no major changes in policy since then. Mexico, however, has initiated extensive regulatory changes in recent years to convert its energy industries and markets from highly regulated monopolies to a more open, competitive system. These changes are expected to provide opportunities for additional sales of U.S. gas over the next few years.

Mexico has a long tradition of national ownership of the means of discovery and production of energy resources. In 1994 and 1995, legislation was passed that effectively opened up the Mexican natural gas industry to more direct foreign participation. The legislation permits foreign ownership of natural gas transportation and electric power generation assets up to 49 percent, so that controlling interest remains with Mexican firms. Action also has been taken to allow foreign participation in production projects on a profit-sharing basis. The impact of these reforms has been limited thus far by concerns about their implementation and the macroeconomic conditions reflected in the devaluation of the peso.

Petroleos Mexicanos (Pemex) remains a dominant force in any outlook for Mexican energy. Pemex controls most natural gas production, and most of the largest gas consumers are currently under long-term contracts. Pemex may have certain incentives to reposition itself away from particular markets, but such business shifts are unclear at present. For example, the far northwest regions of Mexico are not well located for obtaining supplies from Pemex production, most of which occurs in the Yucatan region in the southeast. Potential swaps of developing Mexican production in the northeast for gas delivered to the northwest are one promising option that allows Pemex involvement. Such cooperative arrangements, however, may require some time to develop.

The current trend in crossborder trade to the south is expected to persist for the near future, with Mexico remaining as a significant consumer of U.S. gas. Recent Mexican field development projects have increased indigenous production to about 1.4 trillion cubic feet per year from the 1.3 trillion cubic foot level that had persisted since the mid-1980's. The outlook for natural gas supplies suffered a significant setback recently with an explosion at a natural gas processing plant in southern Mexico in July 1996. This caused a 33-percent loss of natural gas processing capacity in the country, although smaller plants at the facility may resume operations soon. As a result, Mexico is expected to increase imports of U.S. gas by roughly 100 billion cubic feet per year. Greater development of Mexico’s bountiful gas resources will take some time, during which the gas industries in both countries can evolve new ways of doing business together.

Future Challenges

The stages and operations of the natural gas industry have been integrated to an unprecedented degree across North America. The evidence seems clear that regional markets have become interrelated, although the degree of integration between any two markets is not uniform and can vary over time with changing market conditions. With increased integration, changes in any region will influence operations elsewhere. U.S. producers must anticipate the consequences of the successes and failures of supply activities in other regions of the country as well as in Canada and Mexico. Likewise, changes in demand, both short term (e.g., weather) and long term (structural change), may affect the success of supply projects in other regions.

Changes in response to the movement to less regulation have occurred rapidly. For the near term, it is likely that the producing industry will continue along the path it has taken in recent years. Thus, operations will become increasingly consolidated. Some firms will form alliances or mergers in a horizontal direction to establish a stronger market position. Other firms will develop in a vertical direction, combining production operations and marketing activities. These combinations will not necessarily extend to all firms. Undoubtedly, numerous producing firms may continue as entities focused solely on the efficient discovery and development of natural gas.

Two longer term problems for suppliers are likely. Cost containment is essential, but this is a continuation of a traditional requirement for suppliers in most industries. Secondly, the most significant future changes for the gas industry may be driven more by external events related to the regulatory reform of the electric power industry than by any likely (or expected) internal events. Such external forces probably comprise the next major challenge for the industry.

Electric generation is an important gas-consuming sector, and at the same time electricity is a major energy source that competes directly with gas in many markets. It is still highly uncertain how regulatory reform of the electric power industry will alter energy markets. Gas producers will need to position themselves to exploit opportunities and resolve difficulties. The options chosen by producing firms will be a major factor in determining the industry’s future path.

Gas producers need to position themselves to take advantage of market and industry changes, whether transitory or long-lasting. Gas producers have shown interest in diversification into other endeavors. The Chevron and NGC merger is intended to provide a commercial option for customers to enjoy one-stop energy shopping. The convenience of this approach should attract at least some additional customers, and it serves to mitigate the risk of supplying any particular energy form. Events or conditions that might negatively affect gas producers may pose opportunities for suppliers of other energy. For example, customers with the potential to shift to other fuels may be retained by a multiple-fuel firm as the customer selects among the low-cost options of that firm, without having to change to another supplier.

The natural gas industry has changed vastly with reduced regulation, which necessitated change, innovation, and adaptation in virtually every phase of operation. Difficulties will undoubtedly continue to confront firms in the industry. Successful firms are those that will adjust and avoid severe difficulties at least as quickly as their competitors.