

**Development of Natural Gas
and
Pipeline Capacity Markets
in the
United States**

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The deregulation of the natural gas industry in the United States has given free rein to market forces in most of the industry. The main goal of deregulation was to liberalize natural gas trading and supply, the industry segments with the greatest potential to operate as competitive markets. Another major goal was to improve the regulatory oversight of pipeline transportation, which is dominated by natural monopolies.

The wholesale natural gas market became the target of radical liberalization. Natural gas prices were liberalized, entry to the market was deregulated, and pipeline transportation was unbundled from natural gas sales. These measures helped create a competitive wholesale market. In pipeline transportation, economic regulation has gradually moved away from direct price setting to price flexibility, to allow pipeline companies to adjust more readily to changing market conditions. Deregulation has greatly benefited the participants in the U.S. natural gas industry.

This paper examines the development and functioning of natural gas and gas transportation markets in the United States. It first provides an overview of the deregulation of the U.S. natural gas industry, then looks at market structure, the organization of trading, and contracting practices in the natural gas market. It analyzes the trading of pipeline capacity in primary and secondary markets and the regulation of pipeline transportation. It then identifies mechanisms that pipeline companies use to coordinate the many bilateral transactions in natural gas and transportation markets in order to optimize pipeline transportation in the deregulated natural gas industry. Finally it summarizes the main achievements of deregulation of the U.S. natural gas industry.

Deregulation and Structural Changes

The U.S. natural gas industry has gone through a complete cycle of government intervention during the past 60 years. During the first several decades the gas industry enjoyed only limited oversight by the government. Then came the Natural Gas Act of 1938, which established a basis for regulating gas prices and the activities of gas companies. Regulation gradually tightened over the next forty years. Interstate transactions — those between participants in two different states — came under regulation by the Federal Energy Regulatory Commission (FERC). Intrastate transactions came under regulation by state public utility commissions.

Heavy regulation produced poor results. Low wellhead prices discouraged exploration for and production of natural gas. Transportation and distribution markets became monopolized. The retail prices of natural gas were distorted and did not reflect its economic value. All this generated large inefficiencies in all segments of the gas industry and imposed high costs on consumers. A wave of gas shortages in the late 1970s prompted a search for new ways to regulate the gas industry — ways that would allow more room for decentralized transactions among industry participants.

Deregulation of the U.S. natural gas industry in the past 20 years has focused primarily on interstate gas transactions. Since the major producing and consuming regions in the United

States are separated by several state borders, deregulation of interstate gas transactions had a major impact on the operation and efficiency of the natural gas industry. The deregulation of such transactions started in 1978, when Congress adopted the Natural Gas Policy Act authorizing FERC to liberalize interstate natural gas markets. In 1989 Congress approved legislation liberalizing wellhead gas prices, and in 1992 legislation freeing up interstate natural gas transactions. And during the 1980s and 1990s FERC introduced executive orders that gradually established a framework for the actions of market forces in the natural gas industry.¹

Regulatory change

Among the regulatory measures, FERC Orders No. 436 of 1985 and No. 636 of 1992 had the greatest impact on how the natural gas industry operates. By Order No. 436, FERC instituted an open access regime for interstate pipeline transportation. This regime enabled local distribution utilities and large end users to bypass pipeline companies' gas sales and purchase natural gas directly from producers. Although the open access regime was voluntary for pipeline companies, it was widely accepted because it enabled them to increase the utilization of pipelines. But large-scale implementation took place only after FERC resolved the issue of how the costs of the transition to open access were to be distributed.

Before 1985 pipeline companies concluded long-term take-or-pay supply contracts with gas producers to secure gas supply for distribution utilities and end users. Order No. 436 allowed these customers to exit from long-term supply contracts, but left the pipeline companies with large take-or-pay obligations to producers. Pipeline companies were hesitant to implement the open access regime until FERC Order No. 500 allowed them to pass a share of the transition costs to procurers, distribution utilities, and end users.

Order No. 436 was followed by the Wellhead Decontrol Act of 1989, which deregulated the wholesale price of natural gas in all interstate transactions. This legislation freed gas producers from the burden of regulation and promoted competition in the wholesale natural gas market.

Order No. 636 introduced the most radical regulatory change in the gas industry since the beginning of regulation in 1938. The order required pipeline companies to unbundle, or separate, natural gas sale operations from pipeline transportation activities and set up separate transportation and trading affiliates. This supported the development of natural gas marketing, which was deregulated and opened to competition. The deregulated prices of natural gas attracted many new companies into marketing and promoted fierce competition among marketing firms.

¹ Major legislative and executive measures were the Wellhead Decontrol Act of 1989, the Energy Policy Act of 1992, and FERC Orders No. 380, 436, 500, 636, and 577. For more information see Pierce 1988 and De Vany and Walls 1995, or U.S. Department of Energy 1995a.

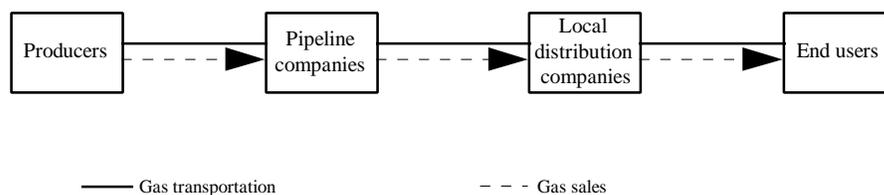
Order No. 636 also reformed the regulation of interstate pipeline transportation to promote fair rates and minimize regulatory distortion of natural gas prices. And it allowed resale of transportation contracts by shippers. That led to the development of a secondary transportation market, where shippers can purchase pipeline capacity from other shippers that have temporarily or permanently spare capacity. The secondary transportation market, known as the capacity release market, promotes efficient allocation of transportation contracts among shippers and high utilization of natural gas pipelines.

Order No. 636 was followed by a series of measures by FERC that were designed to promote competition in the natural gas market and increase flexibility in pipeline transportation. FERC issued orders and proposals to increase transparency and flexibility in short-term capacity resale, allow shippers choice in delivery locations on interstate pipeline systems, and promote the standardization of contracts and pipeline system operation. FERC works with gas industry representatives in formulating new regulatory measures, helping to ensure that the measures adopted broadly benefit industry participants. FERC is now focusing on the development of a short-term transportation market where short-term capacity and interruptible contracts can be traded among pipeline companies and shippers. This market will lead to more efficient pricing of transportation services and enable pipeline companies to sell unsubscribed pipeline capacity.

Structural change

Deregulation has changed the structure of the gas industry in the United States. Before 1985 the industry was vertically separated into production, pipeline transportation, and distribution (figure 1). But with all transactions tightly regulated and completed under long-term contracts, the industry was de facto vertically integrated. Distribution companies could not choose a pipeline company unless their long-term supply contract expired. Most marketed production was sold under long-term take-or-pay contracts between producers and pipeline companies. So little competition occurred among gas producers despite the large number concentrated in several large producing areas along the Gulf Coast and in West Texas.

Figure 1 Traditional Structure of the U.S. Gas Industry, before 1985



The introduction of open access to interstate pipeline transportation in 1985 limited the use of long-term contracts and introduced competition to the wholesale gas market (figure 2). Gas marketing emerged as a new segment of the natural gas industry. Local distribution companies and large end users with direct connections to the interstate pipelines started to contract natural gas directly from producers. Many large end users

constructed new connecting pipelines to bypass local distribution companies and gain access to the wholesale market. The unbundling of interstate pipeline transportation in 1992 completed the transformation of the wholesale market into a fully competitive market (figure 3). Buyers of natural gas benefited, as average wellhead prices dropped by 11 percent in real terms between 1988 and 1994.

Figure 2 Structure of the U.S. Gas Industry with Open Access to Pipeline Transportation, 1985-92

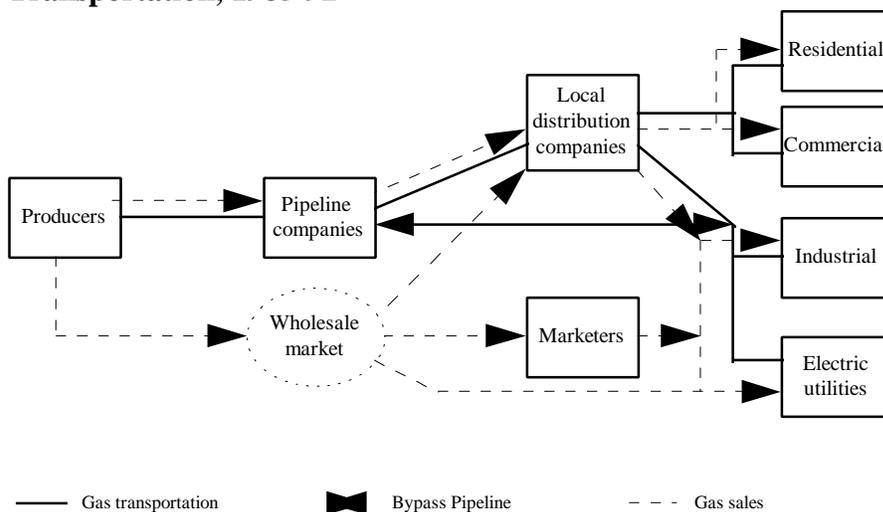
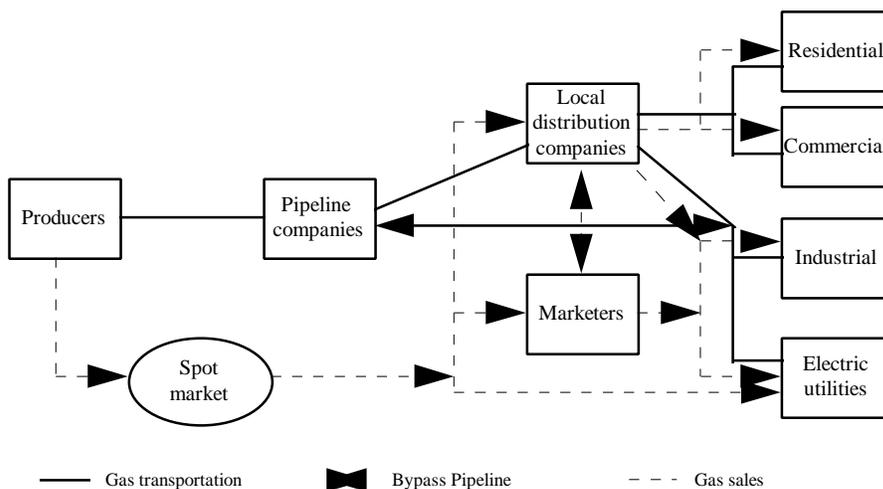


Figure 3 Structure of the U.S. Gas Industry after Unbundling of Sales from Pipeline Transportation, after 1992



The retail market has also experienced the introduction of open access and unbundling, but progress in deregulation differs from state to state. Typically, only large end users, such as electric utilities and industrial customers, are eligible for open access to interstate pipelines. These customers have benefited a great deal from the deregulated wholesale gas

market.² Between 1988 and 1994 the average real price paid by industrial consumers and electric utilities decreased by 15 percent and 19 percent (table 1). Small end users (commercial and residential users) remain captive to local distribution companies because their annual consumption is below the eligibility threshold for open access.³ These end users saw a decline of only 3 percent in the real average price they paid for natural gas deliveries between 1988 and 1994.

Table 1 Average Natural Gas Prices and Price Changes, 1988 and 1994
(1994 dollars per thousand cubic feet)

Category	1988	1994	Percentage change
Wellhead	2.05	1.83	-11
City gate	3.54	3.08	-13
End use			
Residential	6.64	6.41	-3
Commercial	5.62	5.43	-3
On-system industrial ^a	3.58	3.05	-15
Electric utility	2.83	2.28	-19

a. On-system sales are sales of natural gas to the end users by a local distribution utility.

Source: U.S. Department of Energy 1995b.

Natural Gas Market

In the now competitive wholesale gas market trading takes place through bilateral decentralized transactions among producers, marketers, local distribution companies, and large end users. Trading has become concentrated in spot markets organized by a number of market centers in producing regions and consumer areas. These spot markets generate efficient price signals about the market value of natural gas, instantly reacting to actual and expected changes in supply and demand.

Deregulation of the gas industry has facilitated the separation of physical and financial trading. Gas market participants minimize supply risks by balancing their demand with gas supply contracts in the short and long term. They minimize price risk by taking financial positions on their gas supply contract portfolio. As a result, two distinct markets have developed in the wholesale natural gas market in the United States: a physical gas market, where contracts for physical natural gas delivery are traded, and a financial gas market, where contracts for price risk management are traded.

² Electric utilities and industrial customers purchased 73 percent and 76 percent of total gas deliveries in the wholesale market in 1995. They use local distribution companies primarily as transporters of natural gas from an upstream gas market to their consumption site.

³ Commercial consumers purchased about 23 percent of total consumption in the wholesale market, while residential customers purchased almost exclusively from local distribution companies in 1995.

Natural gas supply and deliveries

The natural gas market in the United States is the largest in the world, with a supply of 24.3 trillion cubic feet in 1995. Almost 77 percent of this supply was produced domestically in 1995. The rest came from storage withdrawals and imports, each of which accounted for 12 percent. Gas production is concentrated in a large producing region along the Gulf Coast in Louisiana and Texas; smaller producing regions are in Alaska, the Southwest, and the central United States. Imports from Canada provide an important share of gas supply in consumer areas in the Northeast, the Midwest, and the Pacific Northwest.

Natural gas goes primarily to consumption (89 percent in 1995) and additions to storage (11 percent). Natural gas exports are minimal (table 2).

Table 2 Supply and Disposition of Natural Gas in the United States, 1995

	Volume (millions of cubic feet)	Percentage of total
Supply		
Domestic dry production	18,708,969	76.85
Withdrawals from storage	3,024,548	12.42
Imports	2,841,048	11.67
Balancing item	-230,002	-0.94
Total	24,344,563	100.00
Disposition		
Additions to storage	2,609,779	10.72
Exports	154,119	0.63
Consumption	21,580,665	88.65
Total	24,344,563	100.00

Source: U.S. Department of Energy, Energy Information Administration.

Total consumption by end users was 19.7 trillion cubic feet in 1995 (table 3). There are four main categories of consumers: industrial (which accounted for 44 percent of total consumption in 1995), residential (25 percent), electric utilities (16 percent), and commercial (15 percent). Consumption increased steadily between 1930 and the early 1970s, from 1.2 trillion cubic feet to almost 20 trillion cubic feet in 1973. It plummeted during the oil crisis in the late 1970s and early 1980s, but then began increasing again during the past seven years as a result of growth in consumption by industrial consumers and electric utilities (figure 4).

Table 3 Average Prices and Deliveries of Natural Gas to U.S. Consumers, 1995

Consumer category	Average price (dollars per 1,000 cubic feet)	Deliveries (millions of cubic feet)	Deliveries as a percentage of total
Residential	6.06	4,850,318	24.7
Commercial	5.05	3,031,077	15.4
Industrial	2.71	8,579,585	43.6
Electric utilities	2.02	3,196,507	16.3
Vehicle fuel	—	2,674	0.01
Total	3.79	19,660,161	100

— Not available.

Source: U.S. Department of Energy, Energy Information Administration.

The average price of natural gas increased dramatically between 1970 and 1984 but has been steadily decreasing since then (figure 5). Price increases before 1984 were caused by increasing demand for natural gas, price rigidity imposed by regulation, and the impact of the oil crisis. Deregulation and increasing competition in the wholesale gas market have pushed wholesale and some retail prices down since 1985.

Large end users have benefited from the introduction of open access and the unbundling of interstate pipeline transportation. These reforms have enabled them to participate in the cost savings achieved through competition in the wholesale gas market. The nominal average prices of natural gas at the wellhead and at large end users' consumption sites decreased dramatically between 1984 and 1995. The average wellhead price fell from \$2.66 per thousand cubic feet in 1984 to \$1.55 in 1995. The average retail price paid by industrial consumers decreased from \$4.22 per thousand cubic feet in 1984 to \$2.71 in 1995, and that paid by electric utilities from \$3.70 to \$2.02 (see table 3).

Small end users have also benefited from deregulation of the gas industry, but their gains have been much smaller, mainly because of their limited choice in supply. Most small end users remain captive to the local distribution company. State regulation of retail prices has allowed only limited transfer of cost savings from the wholesale market to small users.

The average retail price paid by small end users declined between 1984 and 1988 but then increased again. Commercial and residential users paid on average \$5.55 and \$6.12 per one thousand cubic feet in 1984. In 1988 average prices bottomed at \$4.63 and \$5.47 per one thousand cubic feet. Then they rose again, peaking above the 1984 levels in 1994. In 1995 commercial and residential users paid on average \$5.05 and \$6.06 per one thousand cubic feet.

Retail prices of natural gas vary widely across the United States. Consumers in the Northeast and Southeast tend to face the highest prices, while those in the Midwest, Pacific Northwest, and Southwest enjoy relatively low prices. Regional price differences reflect differences in the source of natural gas supply, proximity to producing regions,

availability of pipeline capacity, and state regulatory regime. The Northeast is relatively far from major producing regions and, together with Florida, lacks the pipeline capacity to bring more natural gas from the Gulf of Mexico. Louisiana and Texas are both major natural gas producing states, while Illinois and California import large quantities of low-priced natural gas from Canada (figure 6).

Physical gas market

The physical wholesale gas market in the United States is very competitive. Both supply and demand sides of the market involve participants from all segments of the industry. Producers, pipelines, marketers, local distribution companies, and large end users both buy and sell positions to minimize the costs and risks of natural gas supply. Transactions are concluded on a bilateral basis between market participants; many of them involve intermediation by gas marketers. Most natural gas trading takes place in spot markets organized by market centers and hubs and facilitated by electronic trading systems.

Physical gas contracts

Natural gas is traded through bilateral gas contracts that specify the conditions of delivery. These contracts have many dimensions that are determined by the conditions of gas supply, the most important being volume, unit price, calorific value, and location, time, and duration of delivery. Gas supply contracts differ a great deal in almost all these dimensions. But the main differentiation in gas contracts is the duration of supply. Three main types of gas contract have been developed during deregulation: long term, medium term, and short term.⁴

Long-term contracts A long-term contract covers deliveries and receipts for more than 18 months. Such contracts typically specify a fixed quantity of gas to be delivered on a monthly basis. They are used primarily by firms that require reliable and long-term commitment to natural gas supply, often to support long-term investment in gas production or transportation facilities.

The prices of long-term gas tend to be flexible and are often indexed to spot and futures prices of natural gas. If the futures market does not generate reliable price signals for the duration of a contract, the parties to the contract can agree on variable or fixed reservation fees that recover the seller's costs of making supply available in the long term. Alternatively, the parties can combine physical and financial contracts to create a de facto "contract for differences" in which they effectively set a floor or cap on price movements during the life of the contract.

⁴ The definitions of gas contracts in this section draw on U.S. Department of Energy 1994.

Long-term contracts were commonly used in the U.S. natural gas industry before 1984. But traditional contractual arrangements created rigidity that later impeded competition in the gas market. Producers, interstate pipelines, and local distribution companies were locked into contractual relationships through take-or-pay or minimum obligation clauses that forced them to pay fixed amounts regardless of delivery. Order No. 436 eliminated this rigidity by transforming long-term gas supply contracts into long-term transportation contracts between pipeline companies and their downstream customers. This allowed independent acquisition of natural gas by downstream customers, but left pipeline companies with substantial transition costs because of their large uncovered obligations to producers. Until FERC allowed the distribution of these transition costs among industry participants, interstate pipelines were hesitant to implement the open access regime (box 1).

Box 1 The Transition Costs of Order No. 436: Dismantling Long-Term Contract Rigidity

Before 1984, pipeline companies and natural gas producers concluded long-term take-or-pay contracts that required the pipeline companies to buy the contracted volume of natural gas or pay a fixed amount for untaken volumes. The pipeline companies in turn transferred these obligations to their downstream customers. Under a minimum payment obligation clause, pipeline customers paid a fixed charge related to contracted capacity and volume even if they did not take any delivery. All participants, tied by their long-term contracts, were unable to purchase or sell natural gas elsewhere. This Contract rigidity became a substantial impediment to implementation of the open access regime in interstate pipeline transportation.

The minimum payment provisions gave pipeline companies little incentive to acquire natural gas from producers at the minimum cost, because they passed through producer prices directly to their downstream customers. Regulatory distortions and the oil crisis of the 1970s contributed to a dramatic increase in producer prices in the late 1970s and early 1980s, leading to numerous complaints by consumers. Order No. 380 eliminated minimum payment obligations in 1984. Order No. 436 allowed pipeline customers to purchase gas independently and transformed long-term supply contracts into long-term transportation contracts. Many large customers stopped purchasing natural gas from pipeline companies, which were suddenly left with large take-or-pay obligations to producers.

The burden of these take-or-pay obligations created substantial transition costs for pipeline companies and turned them against the open access regime. They were unwilling to provide open access to their pipeline systems unless producers and downstream customers took a fair share of the transition costs. These costs were estimated at \$20 billion by 1990, compared with a total book value for interstate pipelines of \$23.8 billion in 1984 (Pierce 1988). In 1987 Order No. 500 resolved this issue by allowing pipeline companies to transfer up to 75 percent of transition costs to producers and downstream customers. In the end, producers absorbed about \$10 billion of the transition costs, local distribution companies \$6.5 billion, and interstate pipeline companies \$3.7 billion.

Source: Pierce 1988 and U.S. Department of Energy, Energy Information Administration.

Medium- and short-term Contracts As traditional long-term contracting became impractical in the deregulated gas market, market participants developed contracts with a shorter duration of gas supply that would give them the flexibility to adjust natural gas contracting to the frequently changing market environment. Contractual flexibility is important for least-cost acquisition of natural gas in deregulated gas markets affected by changes in weather, economic activity, availability of transportation, and the like. Medium-

and short-term gas supply contracts have therefore become increasingly popular among natural gas buyers in the U.S. gas industry.

A medium-term gas contract covers gas delivery for up to 18 months, but the most common medium-term contracts are for a year or less. These contracts usually specify the volume of monthly or daily gas deliveries, including allowed variation. The price of natural gas is typically indexed to spot and futures prices, depending on the location of delivery. Buyers also pay reservation and service fees to the supplier for making natural gas available for delivery and providing variability in the volumes delivered on a daily or monthly basis.

Short-term gas contracts are frequently traded in natural gas spot markets. A typical short-term contract — a spot contract — is for delivery during one calendar month. The spot contract specifies a fixed price for the natural gas, equal to the prevailing market price at the time of contract completion. Delivery is for a fixed volume, with consistent daily deliveries over the calendar month. Trading of a spot contract can take place anytime before the delivery month and is terminated about five business days before the first day of the delivery month.

Contracts for less than one calendar month are typically used for balancing. Market participants that ship natural gas through the pipeline system are required to maintain a monthly balance between the volumes they inject and withdraw. If shippers withdraw more natural gas than they inject, they purchase the missing gas in the spot market in the form of a balance contract. Otherwise, they will incur penalties imposed by the pipeline companies.

A large volume of gas trading in the spot market leads to a need for standardized gas contracts to lower transaction costs. Interactions among hundreds of participants in the spot market become too complicated if the parties to contracts must develop and formulate all contract dimensions every time they conclude a transaction. Many transactions are concluded rapidly by telephone or over electronic networks, with the contracts signed later. If traders cannot trade under commonly accepted standards, they are hesitant to conclude deals this way. Standardizing contract language, the terms and conditions of transactions, and the use of contracts should reduce the time and cost of negotiating and administering contracts.

To promote standardization in the U.S. gas market, industry participants set up the Gas Industry Standard Board, a nonprofit organization. The board cooperates with FERC, state public utility commissions, and other industry associations in developing standards for operations in natural gas and transportation markets. Its efforts include the development of a standardized short-term gas contract (box 2).

Box 2 Developing a Standardized Short-Term Gas Contract

Numerous calls from the industry prompted efforts by the Gas Industry Standard Board to develop a standardized contract for gas sale and purchase. After a year of drafting and consultation with the industry, the board presented a model short-term gas purchase and sale contract for comments in 1996. The model contract has three parts:

- The base contract, containing the names of contract parties and the contract provisions (selected from the general terms and conditions section).
- General terms and conditions, containing the list of all available contract provisions.
- Transaction confirmation, specifying the price, quantity, delivery points, delivery period, and type of transaction (firm or interruptible).

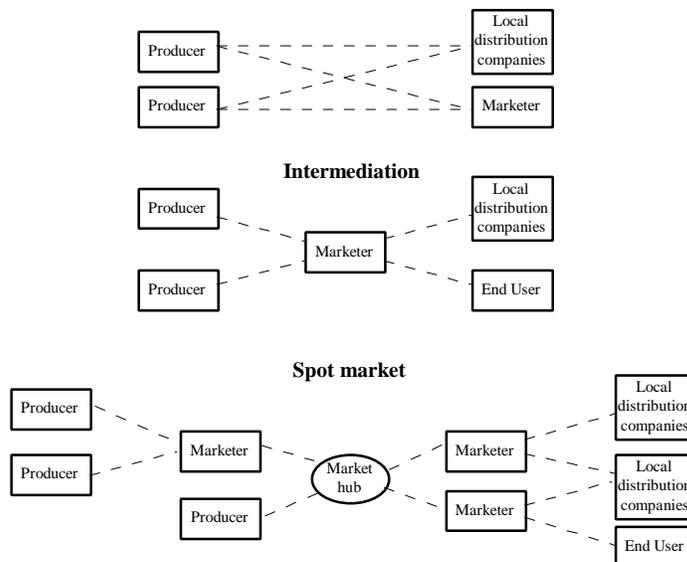
The model contract should facilitate transactions in spot markets, particularly on the electronic data interchange.

Source: Gas Industry Standard Board.

Organization of natural gas trading

The organization of natural gas trading has changed dramatically as a result of deregulation. Traditionally bilateral, transactions now often involve intermediation by natural gas marketers (figure 7). Marketers aggregate the demand of many end users and small local distribution companies and trade natural gas on their behalf, reducing the cost of transactions in the natural gas market. The concentration of trading in market centers and hubs has led to the development of natural gas spot markets. And the introduction of electronic information systems has promoted electronic trading in these spot markets.

Figure 4 Organization of Trading in the Wholesale Gas Market



Bilateral Trading In bilateral trading, the traditional form of natural gas trading, buyers purchase natural gas directly from producers or other natural gas suppliers. Natural gas is traded under long-, medium-, and short-term supply contracts. Depending on the agreement, one of the parties to a contract arranges transportation of natural gas to the delivery point. Trading is decentralized, with each buyer and seller shopping around for the best terms.

Bilateral trading benefits market participants because it allows them to complete only those transactions that suit their needs. Liquid spot and futures markets give price signals about the market value of natural gas, helping market participants make decisions about the optimal structure of their contract portfolio. They can combine long-, medium-, and short-term contracts in a way that minimizes the acquisition costs for natural gas and maximizes the reliability of supply.

But the increasing complexity of the gas market reduces the efficiency of bilateral transactions. Bilateral dealing segregates supply and demand into many portions that players seek to match at the minimum cost. Each market participant must bear the transaction costs incurred in searching for the least expensive natural gas or in adjusting its contract portfolio to the changing market. But some market participants do not have the ability and the necessary information to complete transactions at the minimum cost. These participants will be willing to pay a fee for intermediation of transactions that will give them the desired supply reliability at the minimum cost.

Participants with high consumption and load factors⁵ tend to conclude bilateral transactions themselves, because natural gas contracting and pricing is relatively simple. Low-volume users lack the resources to complete transactions at the minimum cost and therefore rely on intermediaries. But if markets are very dynamic, even high-volume users may find it less expensive to authorize an intermediary to secure gas supplies than to do it themselves.

Marketing The demand for intermediation of transactions in the gas market has given rise to natural gas marketing companies, which complete transactions on behalf of other market participants. Transactions are still bilateral, but they are completed between a marketer and other parties, such as producers, large end users, or local distribution companies. Marketers aggregate supply and demand for natural gas and match their clients' offers and bids at the least cost. Marketers charge a fee for intermediation, but it must be low enough so that market participants' total cost of gas supply is lower than the cost of individual gas acquisitions. Otherwise, market participants will not buy marketers' services.

Aggregation of demand and supply allows marketers to diversify the risk of demand and supply mismatch. This risk arises when market participants with different demand

⁵ Load factor measures the utilization of pipeline capacity by an end user or shipper. It is calculated as the ratio of average daily throughput to peak-day throughput or the maximum daily quantity.

characteristics try to match supply and demand individually. Marketers are able to pool the risks of contracts in one portfolio that gives them flexibility to adjust purchasing or selling strategies in response to changes in the market. The larger a marketer's portfolio, the better able the marketer is to diversify individual supply and demand risks.

Marketing companies constitute a dynamic segment of the U.S. natural gas industry. Producers, local distribution companies, and large end users have found trading through marketing companies beneficial because marketers offer both traditional gas supply services and a large variety of hedging instruments that reduce price and supply risks. The first marketing companies emerged in the late 1980s, but their numbers surged after implementation of Order No. 636. Producers, pipeline companies, and local distribution companies formed marketing subsidiaries that took over natural gas acquisition and sales from the parent companies. The share of deliveries arranged by marketers increased from 20 percent in 1987 to 49 percent in 1995 (Interstate Natural Gas Pipeline Association of America 1993 and 1996).

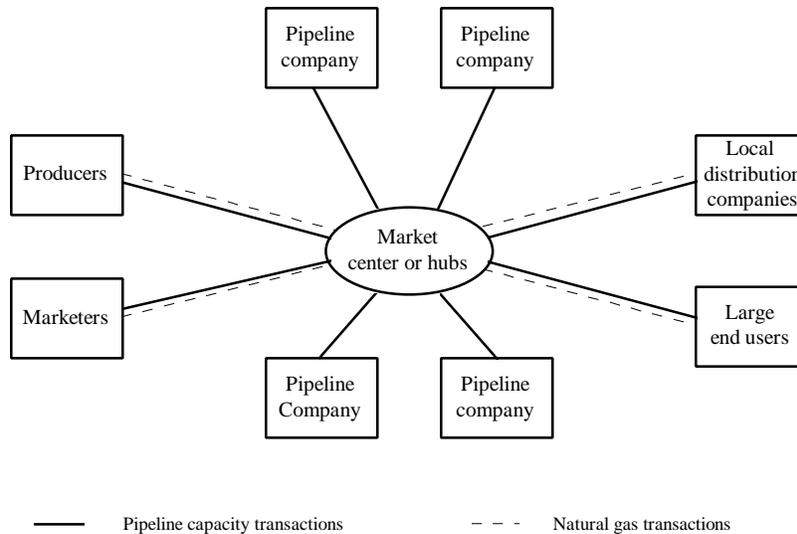
The efficiency of trading intermediated by marketers depends on the fees they charge for services. The U.S. gas marketing segment is very competitive. Marketing fees and operations are liberalized, and the segment is open to entry. Marketing firms compete fiercely for market share and customers. The increasing complexity of natural gas markets has forced marketing companies to expand and diversify in order to accommodate their clients' diverse needs. In 1995 and 1996 the marketing segment experienced a wave of mergers and acquisitions intended to achieve "operating economies of scale, superior databases and the ability to offer superior risk management products" (*Energy Online Daily News*, February 27, 1996).

The restructuring of gas marketing has increased the market shares of the top competitors. For example, Chevron Corporation and NGC, the second and sixth largest gas marketers, merged in 1996 to create the largest marketing company in the United States, with average daily sales of 10 billion cubic feet. Similar mergers took place between other large players, increasing the concentration of sales. While the top 10 marketers arranged average daily sales of about 31 billion cubic feet, or 42 percent of U.S. daily consumption, in 1994, the top four marketers accounted for this volume in 1996 (U.S. Department of Energy 1996). This market concentration leaves little room for small marketing companies. But small marketers play an important part in local markets, where they meet the needs of local customers that are not commercially attractive to major marketers.

Market Centers and Spot Markets The liberalization of natural gas prices and increasing flexibility in the natural gas market have promoted the development of market centers and hubs. Transactions in the wholesale market have gradually moved from wellheads or consumption sites to hubs at major interconnections of interstate and intrastate pipelines. Hubs were formed and are typically operated by one or several interstate pipeline companies that own the pipelines interconnecting at the hub. Hubs allow market participants to acquire natural gas from several independent sources and ship it to several different markets (figure 8). This eliminates the need to contract natural gas and pipeline

capacity all the way from the wellhead to the consumption site. Instead, shippers can combine supply routes across several hubs to diversify supply risks.

Figure 5 Trading in Market Centers and Hubs



Hubs have become very popular among marketers and other players in the gas market. Hub operators have gradually increased the scope of hub services from physical transfer of natural gas to storage, processing, and trading services (box 3). The large variety of services has led even more shippers to use hubs for transportation and acquisition of natural gas. The recent introduction of electronic trading systems has allowed the separation of trading from physical infrastructure and led to the development of market centers connected to one or several hubs by electronic networks. Electronic trading allows market participants to trade natural gas and pipeline capacity at all interconnected hubs and pipelines (see U.S. Department of Energy 1996).

Box 3 Market Center and Hub Services

Market centers and market hubs offer a large variety of services. These are the most commonly used ones:

Wheeling—Essentially a transportation service in which gas is transferred from one interconnected pipeline to another through a header (hub), by displacement (including exchanges), or by physical transmission over a market center pipeline.

Parking—A short-term transaction in which the market center holds the shipper's gas for redelivery at a later date. Often uses storage facilities, but may also use displacement or variations in line pack.

Loaning—A short-term advance of gas to a shipper by a market center that is repaid in kind by the shipper a short time later. Also referred to as advancing, drafting, reverse parking, and imbalance resolution.

Storage—Storage that is longer than parking, such as seasonal storage. Injection and withdrawal operations may be separately charged.

Peaking—Short-term (usually less than a day and perhaps hourly) sales of gas to meet unanticipated increases in demand or shortages of gas experienced by the buyer.

Balancing—A short-term interruptible arrangement to cover a temporary imbalance. The service is often provided in conjunction with parking and loaning.

Gas sales—Sales of gas that are used mainly to satisfy the customer's anticipated load requirements or sales obligations to others. Gas sales are also listed as a service for any market center that is a transaction point for electronic gas trading.

Title transfer—A service in which changes in ownership of a specific gas package are recorded by the market center. Title may transfer several times for some gas before it leaves the center. The service is merely an accounting or documentation of title transfers that may be done electronically, by hard copy, or both.

Electronic trading—Trading systems that either electronically match buyers with sellers or facilitate direct negotiation for legally binding transactions. A market center or other transaction point serves as the location where gas is transferred from buyer to seller. Customers may connect with the hub electronically to enter gas nominations, examine their account position, and access e-mail and bulletin board services.

Administration—Assistance to shippers in the administrative aspects of gas transfers, such as nominations and confirmations.

Compression—Provision of compression as a separate service. If compression is bundled with transportation, it is not a separate service.

Risk management—Services that relate to reducing the risk of price changes to gas buyers and sellers — for example, exchange of futures for physicals.

Hub-to-hub transfers—Arranging simultaneous receipt of a customer's gas into a connection associated with one center and an instantaneous delivery at a distant connection associated with another center. A form of "exchange" transaction.

Source: U.S. Department of Energy, Energy Information Administration.

The first hub in the United States, the Henry Hub, was established in May 1988 in Erath, Louisiana (box 4). Since then, more than 50 hubs have been created across the United States. The largest hubs are the Henry Hub and the Katy Hub, in Texas. There are also about 32 market centers operating in the United States, most located at large hubs in Texas and Louisiana. One of the most important market centers in consuming regions is the Ellisburg-Leidy Center in Pennsylvania (U.S. Department of Energy 1996).

Box 4 The Development of Hubs and Market Centers: The Henry Hub

The Henry Hub is a major natural gas interchange center near Erath, Louisiana, operated by Sabine Pipe Line Company, a subsidiary of Texaco. Marketers and traders at the Henry Hub have access to large consumer markets in the Midwest, Northeast, Southeast, and Gulf Coast area through nine interstate and three intrastate interconnecting pipelines.

The Henry Hub became operational in 1988 as the first hub of its kind in North America. The volume transported through the Hub increased from 230 million cubic feet of gas a day in 1989 to 550 in 1995, and Sabine has the capability to transport more than 1 billion cubic feet of gas a day across the hub. Natural gas trading at the Henry Hub began in 1988 and has developed over time into a large and liquid spot market. The Henry Hub became the pricing point for the New York Mercantile Exchange (NYMEX) natural gas futures contracts in April 1990 and the NYMEX options contracts in 1992.

The Henry Hub has attracted major natural gas traders thanks to Sabine's ability to offer shippers the flexibility to change supply sources and markets through interconnecting pipelines. Sabine's pipeline system is relatively small, with only 189 miles of pipeline, but it can move gas in both directions in response to gas prices and has interconnections with 14 interstate and 22 intrastate pipelines. Sabine was the first pipeline operator in the U.S. gas industry to use operational balance agreements — agreements among the interconnected pipeline companies to resolve monthly imbalances among shippers so that individual shippers do not incur an imbalance penalty. Sabine signed such an agreement with the Natural Gas Pipeline Company in 1989, and by now has operational balance agreements with all interconnecting pipelines. These agreements have contributed to the popularity of the Henry Hub among gas traders and the high satisfaction of shippers with Sabine's services.

Source: Interstate Natural Gas Pipeline Association of America

Spot markets have been organized at almost all major market centers and hubs in the United States as well as at major city gates.⁶ Today there are more than 50 spot markets in the United States. The most important is at the Henry Hub, where natural gas has been traded since 1988.

The most important role of spot markets is to generate efficient price signals about the market value of natural gas. In a competitive spot market prices reflect the short-run marginal cost of gas at the location of the market — that is, the spot price is equal to the value of a marginal unit of gas traded in the spot market at a particular time and thus reflects the market value of gas at that time. In practice, spot prices are derived from the prices of a large number of gas contracts traded in a spot market.

Market participants use spot prices to evaluate their gas contract portfolios. They also use spot prices for pricing natural gas traded under bilateral supply contracts, particularly long-term supply contracts. Thus the pricing of most natural gas deliveries is linked to spot market prices, and as a result, most participants in the gas market face efficient prices as long as spot markets are competitive and well functioning.

⁶ City gates are delivery points on interstate pipelines where local distribution companies and large end users receive interstate gas deliveries. Transportation beyond a city gate takes place on interstate or distribution pipelines. City gates are located near large consuming areas. In the United States the largest city gate is in Chicago (U.S. Department of Energy 1995a).

Electronic Trading Electronic trading is a new form of natural gas trading in the United States. Electronic trading systems either electronically match buyers with sellers or facilitate direct negotiations for gas transactions. In the first case market participants post offers and bids on the electronic system, which matches them anonymously. Transactions are completed instantly as the system registers all offers and bids that are matched. In the second case electronic systems identify buyers and sellers and facilitate their transactions. Since electronic systems are connected to many market centers and pipeline companies, market participants can trade natural gas and pipeline capacity in several locations at once. Market participants must purchase access to the electronic system, but they can use regular computer hardware to support transactions in the system.

Electronic trading reduces transaction costs and promotes efficient pricing of natural gas. Electronic systems aggregate demand and supply at one point, matching offers and bids at the minimum cost to participants and generating systemwide prices that reflect the opportunity costs of natural gas.

The beginnings of electronic trading can be traced to the electronic bulletin boards established by interstate pipeline companies in 1993 to support resale of pipeline capacity. Standardization of these boards simplified trading of pipeline capacity and showed the advantages of electronic trading. In late 1994 three commercial electronic trading systems were introduced that allowed market participants to trade natural gas and pipeline capacity across several markets and pipelines. By the end of 1996 electronic systems had been introduced by almost all major pipeline companies.

Electronic systems are now used for trading natural gas, pipeline capacity, and storage and for communication between pipeline companies and shippers. These systems also are linked to other commercial networks that supply information and news relevant to the gas industry. The largest system, Altra Streamline, is linked to eight market centers in the United States and Canada and 45 electronic bulletin boards of interstate pipelines. The average daily volume traded in this system ranges from 10 million to 200 million cubic feet. The second and third largest systems, Channel 4 and Quick Trade, connect four and three market centers, respectively, and a number of electronic bulletin boards. Major interstate pipeline companies operate electronic systems that give access primarily to their own electronic bulletin boards. Small systems integrate with large ones reflecting the demand for services that allow trading across all major gas markets in the United States (U.S. Department of Energy 1996).

A new role for storage

Natural gas storage has played a significant part in ensuring adequate gas supplies since the 1930s. Pipeline companies and local distribution companies used storage facilities to meet seasonal and peak gas demand during heating seasons and to balance pipeline operations on a daily basis. The traditional role of storage was to ensure high reliability of gas supply; cost-effectiveness in storage operations was neglected.

A new role for gas storage is to promote efficient transactions in the deregulated natural gas market. Storage operation is being unbundled from pipeline transportation and deregulated, and cost-effectiveness is being emphasized. As the unbundling of pipeline transportation has improved price discovery at various points on the pipeline system, storage facilities have increasingly been used to arbitrage locational and time differentials in gas prices. Storage operators take advantage of swings in spot prices by selling natural gas at high prices and buying at low prices. These transactions benefit market participants through greater availability and more efficient pricing of natural gas in the spot market.

Storage also contributes to more productive use of pipeline capacity. Storage facilities are placed at market hubs and city gates, where storage operators offer a range of services such as storing, parking, loaning, and balancing natural gas.⁷ Shippers and pipeline companies use these services to balance their shipments and flows of natural gas in the short, medium, and long term. Storage thus enables pipeline companies to increase load factor and reduce seasonal load variations. Intelligent use of storage within a system of hubs can create significant throughput capacity for the transportation grid at a capital cost of 1 to 2 percent as much as the next cheapest alternative.⁸

The most common types of underground storage in the United States are depleted reservoirs in oil or gas fields, salt caverns, and aquifers. A small amount of gas is also stored in liquefied natural gas and propane-air storage facilities. At the end of 1995 there were 403 underground storage facilities in operation in the United States, with total working capacity of 3.8 trillion cubic feet and daily deliverability (the amount that can be withdrawn in a day) of 69.3 million cubic feet of natural gas. Depleted oil or gas field storage accounted for almost 88 percent of working capacity, compared with 10 percent for aquifers and 2 percent for salt caverns. The share of depleted gas and oil fields in daily deliverability was 86 percent, that of salt caverns 14 percent and that of aquifers 10 percent (U.S. Department of Energy 1995c).

The commercial success of storage in deregulated gas markets depends on high deliverability of natural gas to the market rather than on total working capacity. Storage operators need to be able to inject and withdraw natural gas quickly to react to highly volatile spot prices. As a result, salt cavern storage facilities have become increasingly popular among storage operators in the United States. Because there is no resistance in a salt cavern, gas can flow into and out of the cavern readily. The operator of an average salt cavern is able to withdraw all its gas in 10 to 11 days and refill it in only 20 days, compared with nearly 60 days to withdraw all gas from traditional depleted gas field storage (U.S. Department of Energy 1995c).

Salt cavern storage facilities are steadily gaining market share at the expense of traditional storage using depleted gas or oil fields. New storage projects completed in 1995 added

⁷ Twenty-six of the 39 market centers in the United States and Canada offer storage as a major service (U.S. Department of Energy 1996).

⁸ Approximately \$0.5 billion invested in a system of hubs with high-deliverability salt storage can displace \$40 billion to \$80 billion of incremental expansion in the existing pipeline infrastructure (Bickle 1996).

about 47 billion cubic feet of working gas capacity and 1,395 million cubic feet of daily deliverability to the storage market. Although salt cavern storage facilities accounted for only about 30 percent of the new capacity, they accounted for 65 percent of the new daily deliverability.

The location and ownership of salt cavern storage reflect the commercial focus of storage operators in deregulated gas markets. Most salt cavern storage is in market centers and hubs. For example, 13 of 19 salt cavern facilities in the Southwest are in market centers. Independent operators control 50 percent of salt cavern storage facilities, giving them a 12 percent share in daily deliverability, though only an 8 percent share in working capacity.

Financial gas market

The opening of the gas industry to competition and the development of natural gas spot markets have generated price volatility that was absent in the tightly regulated industry of the past. As industry participants started to look for ways to minimize price risk through financial instruments, markets responded by offering financial natural gas contracts used for hedging, speculation, and arbitrage.

There is now a well-developed financial natural gas market. Financial intermediaries and natural gas marketers offer customized financial instruments that transfer risk among industry participants. In addition, two organized exchanges offer several standardized natural gas futures and options contracts used by traders and industry participants to minimize price risk in many gas delivery locations. These contracts have promoted efficiency in the natural gas industry as market participants have taken advantage of arbitrage opportunities in locational prices and regional natural gas markets have become more nationally integrated.

Financial gas contracts

Financial gas contracts are used to manage two types of risk in the natural gas market, price and basis risk. Price risk is generated by the volatile spot market prices of natural gas. Basis risk is the risk of change in the price differential between locations, time periods, and qualities of gas deliveries and between natural gas and other commodities.

Seven major types of financial gas contracts have been developed in the U.S. financial gas market, each using a different technique to manage price and basis risk:⁹

- *Futures contract* — a legal agreement between a party that opens a position on the futures market to buy or sell natural gas and the commodity exchange. The party agrees to accept or deliver, during a specified future month, a certain quantity of natural gas (10 billion British thermal units per contract) meeting quality and delivery conditions described by the exchange. If delivery takes place, it occurs during the delivery month at a prescribed futures settlement price. Futures contracts are traded

⁹ The definitions of financial gas contracts draw on U.S. Department of Energy 1994 and NYMEX 1996.

exclusively on regulated exchanges and are settled daily based on their current value in the marketplace.

- *Forward contract* — a supply contract between a buyer and seller under which the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of natural gas at a predetermined price on a specified future date. Payment in full is due at the time of, or following, delivery. A forward contract differs in this way from a futures contract, under which settlement is made daily, resulting in partial payments over the life of the contract.
- *Swap* — custom-tailored, individually negotiated transaction designed to manage financial risk, usually over for 1 to 12 years. Swaps can be conducted directly by two counterparties or through a third party such as a bank or brokerage house. The writer of the swap, often a bank or brokerage house, may elect to assume the risk itself or to manage its market exposure on an exchange. Swap transactions include interest rate swaps, currency swaps, and price swaps for commodities. In a typical commodity or price swap the parties exchange payments based on changes in the price of a commodity or a market index, effectively fixing the price they pay for the commodity. Settlements are usually made in cash. Natural gas basis swaps are over-the-counter agreements to exchange the difference — called the basis — between the natural gas futures price on the New York Mercantile Exchange (NYMEX) and a fixed price at a specific location.
- *Hedge* — a position taken in the financial market to offset a position in the physical market. The expectation is that gains and losses from price movements in the two markets will consistently offset each other until the position in the financial market is closed (ideally, this occurs at exactly the same time that the position in the physical market is closed). Thus a hedge is a combination of futures and physical contracts that effectively fixes the price of natural gas. Long hedges protect the purchase price, and short hedges the inventory value.
- *Options contract* — a contract that gives its holder the right, but not the obligation, to purchase or sell the underlying futures contract at a specified price within a specified period in exchange for a one-time premium payment. The contract also obligates the writer, who receives the premium, to meet these obligations.
- *Exchange of futures for physicals (EFP)* — a futures contract that has a delivery point other than that in a specified second futures contract. The price of the EFP may then deviate from the price of the specified futures contract. An EFP may be concluded at any time before the close of the market for the specified futures contract by mutual agreement of the two parties holding opposite positions on that contract. The main reasons for trading EFPs are elimination of execution risks, ability to choose a contractual partner, and flexibility in location and supply conditions.

- *Alternative delivery procedure* — a transaction that takes place after the termination of trading in a spot month contract, for example, a futures contract. The buyer may agree with the seller, with whom the buyer has been matched by the exchange, to take delivery under terms or conditions that differ from the terms and conditions of the relevant standardized contract. The exchange must receive notifications of such transactions from the clearing members handling the accounts of the parties to the transactions.

Financial gas contracts are divided into two categories: standardized and nonstandardized. Standardized contracts, such as natural gas futures and options contracts, are offered by and traded in organized exchanges. Nonstandardized contracts are offered by financial intermediaries or natural gas marketers to market participants on a case-by-case basis. Nonstandardized contracts, such as hedges or swaps, tend to vary widely, reflecting the variation in transactions. They developed before standardized contracts, as market participants searched for ways to manage price risk in the natural gas spot market.

Four major types of standardized natural gas futures and options contracts are traded in the United States. NYMEX offers and provides a trading floor for three of them, each with a different delivery location. The first futures contract, traded since April 1990, is for delivery for 1 month to 30 consecutive months, plus the 36th month (though only for the June and December contracts, because these conclude the long-term contracting periods), at the Henry Hub. The options contract for delivery at the Henry Hub was added in April 1992. The Henry Hub futures contract is the most liquid financial gas contract in the United States. (For the specifications of the NYMEX Henry Hub natural gas futures and options contracts, see box 5.)

The second futures contract is for delivery in 18 consecutive months at the Permian Basin in West Texas. This futures contract was introduced on May 31, 1996, and the relevant options contract was launched seven days later. The third futures contract is for delivery in Alberta, Canada, and was launched, together with an options contract, in September 1996.

The fourth natural gas futures and options contracts were issued in 1995 by the Kansas City Board of Trade (KCBT), which also became a trading spot for these contracts. The contracts, called Western Natural Gas Futures and Options, are for delivery for up to 18 consecutive months at the Waha-Permian Hub in West Texas.

Management of price risk

Market participants face substantial price risk in the deregulated natural gas market. Spot prices are volatile, particularly during cold periods. Two spells of extremely low temperatures in late January 1994 and February 1996, for example, caused extreme changes in the spot prices of natural gas at the Henry Hub. While the average spot price in January 1994 was about \$2.25 per million British thermal units, it reached \$3.75 on February 2, 1994, in the midst of the cold spell. Price changes were even more dramatic in 1995. The average spot price in February 1995 was at a record high of \$4.41 per million British thermal units, and spot prices peaked above \$15 just before the coldest weekend, on February 2, 1995.¹⁰ The volatility of spot prices increased from the annual average of about 40 percent to more than 60 percent in February 1994 and almost 140 percent in February 1995 (Natenberg 1996).

Financial gas contracts allow market participants to minimize this price risk in the physical gas spot market by taking positions in the financial gas market. The range of financial contracts available enables them to form the positions in cash and financial markets that best reflect their desired level of risk aversion. Although market participants use financial contracts for hedging, arbitrage, and speculation, the primary use remains to minimize price risk.

¹⁰ Prices at city gates were even more volatile than at the Henry Hub. For example, some industrial customers in Chicago paid \$45 per million British thermal units to avoid imbalance penalties of more than \$60 per million British thermal units (U.S. Department of Energy 1996).

Box 5 NYMEX Division Henry Hub Natural Gas Futures and Options Contract SpecificationsTrading unit

Futures: 10 billion British thermal units.

Options: One NYMEX Division natural gas futures contract.

Trading hours

Futures and options: 10:00 a.m.-3:10 p.m. for the open outcry session. After-hours trading is conducted through the NYMEX ACCESS® electronic trading system from 4 p.m. to 7 p.m., Monday through Thursday. All times are New York times.

Trading months

Futures: 30 consecutive months commencing with the next calendar month (for example, on October 3, 1997, trading occurs in all months from November 1997 through April 2000), plus a long-dated contract, initially listed 36 months out.

Options: 12 consecutive months, plus 18, 24, 30, and 36 months on a June-December cycle.

Price quotation

Futures and options: Dollars and cents per million British thermal units, for example, \$2.035 per million British thermal units.

Minimum price fluctuation

Futures and options: \$0.001 per million British thermal units (\$10 per contract).

Maximum daily price fluctuation

Futures: \$1.50 per million British thermal units (\$15,000 per contract) for the first two months. Initial back month limits of \$0.15 per million British thermal units rise to \$0.30 per million British thermal units if the previous day's settlement price in any back month is at the \$0.15 limit. In the event of a \$0.75 per million British thermal units move in either of the first two contract months, back month limits are raised to \$0.75 per million British thermal units in all months from the limit in place in the direction of the move.

Options: No price limits.

Last trading day

Futures: Trading terminates three business days before the first calendar day of the delivery month.

Options: Trading terminates at the close of business on the business day immediately preceding the expiration of the underlying futures contract.

Exercise of options

By a clearing member to the exchange clearinghouse not later than 5:30 p.m. or 45 minutes after the underlying futures settlement price is posted, whichever is later, on any day up to and including the options expiration.

Option strike prices

Strike prices are in increments of \$0.05 per million British thermal units with at least 15 strike prices above and 15 below the at-the-money strike prices, 15 in \$0.05 intervals, and eight above or below the furthest \$0.05 increment in \$0.25 intervals. In addition, in the first three months strike prices are listed in \$0.25 increments in the \$0.05 surrounding the at-the-money price.

Delivery

Saline Pipe Line Co.'s Henry Hub in Louisiana. The seller is responsible for the movement of the gas through the hub; the buyer, from the hub. The hub fee will be paid by the seller.

Delivery period

Delivery shall take place no earlier than the first calendar day of the delivery month and shall be completed no later than the last calendar day of the delivery month. All deliveries shall be made at an hourly and daily rate of flow as uniform as possible over the course of the delivery month.

Alternative delivery period

An alternative delivery procedure is available to buyers and sellers who have been matched by the exchange subsequent to the termination of trading in the spot month contract. If buyer and seller agree to consummate delivery under terms different from those prescribed in the contract specifications, they may proceed on that basis after submitting a notice of their intention to the exchange.

Exchange of futures for, or in connection with, physicals (EFP)

The commercial buyer or seller may exchange a futures position for a physical position of equal quantity by submitting a notice to the exchange. EFPs may be used to either initiate or liquidate a futures position.

Quality specifications

Pipeline specifications in effect at time of delivery.

Position limits

12,000 contracts for all months combined, but not to exceed 750 in the delivery month or 7,500 in any one month.

Margin requirements

Margins are required for open futures and short options positions. The margin requirement for an options purchaser will never exceed the premium paid.

Trading symbols

Futures: NG

Options: ON

Source: NYMEX

Market participants unable to accept price risk because of technology or demand constraints are willing to pay a premium to reduce the risk to an acceptable level. This demand can be served by a financial gas contract that transfers the risk to the issuer of the contract in exchange for a payment. Such price risk management is often intermediated by natural gas marketing companies or financial intermediaries.

Intermediation of price risk management benefits both marketers and their contractual partners. Marketers have lower risk aversion and better knowledge of markets and hedging strategies than most other participants in the gas market and can therefore provide better and less expensive risk hedging. Marketers sell market participants risk management services in the form of financial gas contracts, at a premium that reflects the risk of the transaction. They then combine the risks of individual financial contracts into one portfolio and minimize the overall risk by taking positions in physical and financial gas markets.

Intense competition among marketers drives premiums down toward the least cost of hedging risk. The increasing complexity of the gas market and competition among natural gas marketers have led to consolidation of the marketing segment as a number of marketing companies have emerged into several large marketing houses in order to reduce costs, diversify services in natural gas markets, and expand into the developing electric

power markets. The critical size of a natural gas marketing firm has increased from 3 billion cubic feet of natural gas per day in 1994 to 5 billion cubic feet in 1995, reflecting the increase in the size of the optimal gas portfolio for a marketing firm (*Energy Online Daily News*, February 27, 1996).

Management of basis risk

The existence of several standardized contracts with different delivery locations signals the presence of basis risk in the natural gas market — the uncertainty that the cash-futures differential will widen or narrow during the time a hedge position is implemented and liquidated.¹¹ Basis risk depends on three price relationships:

- That between the price of a futures contract and the spot price of gas — cash-futures basis.
- That between the spot price at the futures delivery point and the spot price at a different location — locational basis.
- That between the spot price at the futures contract delivery point and the spot price of a similar but not identical commodity at the same location — intercommodity basis.

Strategies to minimize basis risk differ with the type of basis risk involved. Market participants manage cash-futures basis risk using alternative delivery procedures, which allow them to minimize cash-futures price differentials between the expiration of a futures contract and the start of physical gas delivery. This period is five days for NYMEX natural gas futures and one to three days for KCBT natural gas futures. Spot prices can change significantly during this period, leading to a difference between the value of gas acquired through a futures contract and the market value of gas.

Hedging intercommodity basis risk is a complex operation that differs from case to case. If commodities are commercially traded, the ability to minimize this type of basis risk depends on the efficiency of the commodity markets involved. Because heating oil and natural gas, for example, are substitutes in residential heating, their relative prices should reflect the relative values of heating equivalent as long as the markets are efficient. Market participants can minimize the intercommodity risk between heating oil and natural gas by taking positions in cash and financial heating oil and gas markets based on relative price changes. But if qualitative differences in a commodity are not commonly used in the market — for example, calorific value — hedging tools may not be available. In this case parties to supply contracts must protect themselves by explicitly defining delivery conditions and penalties in the contracts.

Locational basis risk is managed through exchange of futures for physicals contracts. EFPs allow hedging of locational basis risk for almost any delivery location on the pipeline system in the United States. But the efficiency of hedging by EFPs depends on the trading volume of EFPs with the same delivery location, which in turn depends on the size of the

¹¹ This definition of basis risk is based on NYMEX's (1996).

spot gas market at that location. EFPs provide effective hedging of locational basis risk only at the most commonly used locations, such as large market hubs or city gates.

The division of the U.S. natural gas market into eastern and western parts has increased the locational basis risk of the NYMEX futures contract with delivery at the Henry Hub. This contract helps hedge price risk for gas supplies directed to the eastern United States, but has proved insufficient for hedging price risk for gas supplies going to the western United States, which originate in West Texas. As the locational price differentials between the Henry Hub and West Texas have increased since the introduction of the Henry Hub futures contract, so has the locational basis risk faced by market participants.

Locational basis risk has also increased because of the growing imports of natural gas from Canada. Since the price risk in Canada is much different from that in the United States, price differentials between the Henry Hub and Alberta, Canada, were large and variable. For this risk too, the Henry Hub futures contract was not an appropriate tool for hedging.

It was in response to the demand for instruments to hedge the locational basis risk in the western United States that the Kansas City Board of Trade launched the Western Natural Gas Futures and Options contract in August 1995. The contract's delivery point at the Waha-Permian Hub in West Texas is better linked with the Western than is the Henry Hub. The commercial success of this contract shows that shippers to the West viewed the locational basis risk at the Henry Hub as a serious problem.

The launch by NYMEX in May 1996 of the futures and options contracts with delivery in Permian Basin, West Texas, only 100 miles from the Waha-Permian Hub, created competition between the two futures contracts. The NYMEX futures and options contracts with delivery in Alberta, Canada, were launched to serve the needs of customers that rely on Canadian natural gas imports.

Trading in the financial gas market

The financial contract market is a dynamic segment of the U.S. natural gas industry. After the start of futures trading in 1990, the volume of traded natural gas futures contracts increased from 0.42 trillion cubic feet in 1991 to 80 trillion cubic feet in 1995, or four times more than the end use consumption of natural gas in that year. The turnover in futures trading was \$125 billion in 1994, about 60 percent more than the turnover in physical gas sales in that year (U.S. Department of Energy 1994). Most trading is done by marketers (which held 34 percent of the open interest on natural gas futures in the first quarter of 1996), producers (25 percent), and financial institutions (20 percent) (NYMEX 1996a). Their shares in previous years were similar. Marketers were also responsible for 60 percent of the number of futures traded on NYMEX in 1993 (U.S. Department of Energy 1994).

The financial gas market is gradually reaching maturity, especially in standardized contracts as indicated by the small share of futures contracts resulting in physical delivery (table 4). On average, only 0.26 percent of natural gas futures contracts traded on NYMEX were held until expiration in 1995, compared with 0.14 percent of crude oil futures contracts (the most mature contract traded on NYMEX), 0.18 percent of heating oil futures contracts, and 3.4 percent of propane futures contracts. The low level of physical delivery indicates that market participants use futures contracts as an instrument for price risk management — their primary purpose — not for physical gas delivery.

Table 4 Delivery Structure of Natural Gas Contracts at NYMEX, 1993-96
(millions of British thermal units)

Year	Deliveries of futures	Futures trading volume	Deliveries of EFPs	Deliveries as a percentage of trading volume
1993	10,417	3,775,517	79,725	0.28
1994	15,923	6,223,401	147,039	0.26
1995	20,025	7,621,742	209,323	0.26
1996	13,223	4,556,290	142,371	0.29

Source: NYMEX.

Most of the final deliveries of financial gas contracts at NYMEX took place under EFPs, whose delivery rate is about 10 times that for futures. While futures contracts are used for hedging and speculation at only three locations (the Henry Hub, West Texas, and Alberta), EFPs can be used for delivery at any location. Thus EFPs can hedge the risk of changing price differentials between a standard delivery location and any location in the nationwide pipeline system and are naturally used more often than standard futures contracts.

The natural gas market has become more efficient with the increasing use of futures contracts. De Vany and Walls (1995) analyzed cointegration between spot and futures prices between June 1990 and June 1994 and found evidence that prices in the futures market accurately reflected the future spot prices of gas at the Henry Hub and seven major spot markets. They also found that the price differentials between locations reflected the costs of transportation. They concluded that the futures prices of a month-ahead contract revealed the closing futures price, and that spot prices in the Henry Hub are an unbiased predictor of the future spot price.

Transportation Market

A natural gas transportation market is a marketplace where pipeline capacity and transportation services are traded. The interstate pipeline transportation market is the most competitive transportation market in the United States because of the unbundling of this industry segment.¹² The supply side of the market consists of interstate pipeline

¹² Intrastate pipeline transportation and distribution are the other two segments of the transportation market in the United States. This section focuses primarily on the interstate pipeline transportation

companies, and the demand side of shippers that purchase pipeline capacity and transportation from the pipeline companies. Shippers are usually marketers, local distribution companies, producers, or large end users. Transactions take place through transportation contracts that define the conditions of transportation and delivery of natural gas.

There are two main transportation markets in the United States: a primary market and a secondary market. In the primary market pipeline companies sell transportation contracts to marketers, local distribution companies, or end users. Typical services are firm, no-notice, and interruptible transportation. In the secondary market pipeline companies and holders of transportation contracts resell unused capacity in the form of firm or interruptible transportation. The U.S. interstate transportation market is regulated by FERC.

The unbundling of interstate pipeline transportation and regulatory changes in 1992 have promoted more transparent and fair pricing of transportation services. Interstate pipeline companies began competing to attract shipments in major markets by reducing transportation prices. Shippers have benefited directly through lower transportation costs, and end users indirectly through lower retail prices for natural gas. Shippers paid on average 16 percent less for interstate pipeline transportation in 1994 than in 1988, while the volume of transported natural gas increased by 15 percent during 1988-94 (transportation costs are measured as the average cost of transmission services from wellhead to the local distributor). The transportation and distribution markup decreased by 20 percent and 42 percent in real terms for industrial end users and electric utilities, while it remained constant for commercial and residential end users (U.S. Department of Energy, 1995a).

Structure of the interstate pipeline transportation market

The interstate pipeline transportation market is dominated by primary transportation services, which were used for 69 percent of gas deliveries in 1995 (table 5). Secondary transportation services accounted for the remaining 31 percent. The share of secondary transportation services has been steadily increasing since the secondary market was created in 1993.

market, which has experienced the most radical regulatory change in the past 12 years. The regulatory regime in the other two segments varies from state to state.

Table 5 Structure of the Interstate Pipeline Transportation Market, 1994-95
(percent)

	1994	1995
Primary transportation	71	69
Share arranged by local distribution companies	—	63
Share arranged by marketers ^a	—	37
Secondary transportation	29	31
Firm	13	17
Interruptible	16	14
Share arranged by local distribution companies	26	24
Share arranged by marketers ^a	74	76
All transportation	100	100
Share arranged by local distribution companies	—	51
Share arranged by marketers ^a	—	49

— Not available

^a Includes end users.

Source: Interstate Natural Gas Pipeline Association of America.

The most active players in the primary market are local distribution companies, which arranged 63 percent of primary deliveries in 1995; marketers and end users arranged the remaining 37 percent. The ownership of transportation contracts has a similar structure: local distribution companies held about 66 percent of interstate pipeline capacity in 1995, marketers 14 percent, end users 8 percent, other pipelines 7 percent, and producers 3 percent.

Transactions in the secondary transportation market are dominated by marketers, which arranged transportation for 76 percent of secondary deliveries in 1995. Local distribution companies' share was only 24 percent and is steadily decreasing. Their share in the overall transportation market is 51 percent, and marketers' share is 49 percent.

The open access regime and unbundling of interstate pipeline transportation have transformed the way in which end users receive their gas deliveries. Before 1985 they received almost all natural gas deliveries through sales from local distribution utilities or a nearby pipeline company. Today they purchase only 52 percent of gas deliveries directly from pipeline or local distribution companies. They purchase the remaining 48 percent in the wholesale market and pay fees to pipeline and local distribution companies for transporting these deliveries to consumption sites.

More than 74 percent of deliveries to end users were transported under firm transportation contracts in 1995, and the remaining 26 percent under interruptible contracts.

Because deregulation of interstate pipeline transportation has not given all end users equal access to transportation and the wholesale gas market, the structure of deliveries differs among types of end users. Electric utilities and industrial customers, which gained the most under open access and unbundling, purchased on average more than 70 percent of their 1995 natural gas deliveries in the wholesale market and bought transportation services from pipeline or local distribution companies. In addition, industrial customers received 9.5 percent of their deliveries directly from interstate pipeline companies in 1995 (U.S. Department of Energy 1996). Electric utilities and industrial customers both took about 60 percent of their deliveries under firm transportation contracts, and 40 percent under interruptible contracts (table 6). Firm transportation contracts offer the security of highly reliable delivery of base load natural gas, while interruptible contracts offer the flexibility to acquire additional gas deliveries in the event of a sudden increase in demand. Industrial consumers and electric utilities purchase firm and interruptible transportation services in different amounts to build a contract portfolio that gives them the minimum acceptable level of supply reliability at the minimum cost.

Table 6 Firm and Interruptible Deliveries of Natural Gas to U.S. Consumers, 1995
(millions of cubic feet)

Consumer category	Firm		Interruptible		Total
	Volume	Percentage of total	Volume	Percentage of total	
Residential	4,846,360 (99.2)	34	3,958 (0.08)	0	4,850,318
Commercial	2,650,412 (87.4)	18	380,665 (12.6)	8	3,031,077
Industrial	5,140,048 (59.9)	36	3,439,537 (40.1)	69	8,579,585
Electric Utilities	1,758,945 (60.5)	12	1,147,860 (39.5)	23	2,906,805
Total	14,398,214 (74.3)	100	4,972,245 (25.7)	100	19,370,459

Note: Figures in parentheses show the percentage breakdown between firm and interruptible deliveries for that category of consumers.

Source: U.S. Department of Energy 1995b.

By contrast to electric utilities and industrial customers, commercial and residential customers have only limited access to the transportation and upstream gas markets. Commercial end users took on average 23 percent of their gas deliveries as a transportation service in 1995 and purchased the rest primarily from local distribution companies (table 7). They took 87 percent of deliveries under firm transportation contracts. Residential customers took almost all their gas deliveries from local distribution companies as firm sales services.

**Table 7 Structure of Natural Gas Deliveries to U.S. Consumers, 1995
(millions of cubic feet)**

Type of delivery	Residential		Commercial		Industrial		Electric utilities		All categories	
	Volume	Percentage of total	Volume	Percentage of total	Volume	Percentage of total	Volume	Percentage of total	Volume	Percentage of total
<i>Firm transportation</i>										
Sales	4,846,360	99.9	2,125,008	70	1,294,546	15	431,014	15	8,696,928	45
Transportation	0	0	525,404	17	3,845,501	45	1,327,931	46	5,698,836	29
Total	4,846,360	99.9	2,650,412	87	5,140,047	60	1,758,945	61	14,395,764	74
<i>Interruptible transportation</i>										
Sales	3,958	0.1	199,930	7	767,687	9	365,507	13	1,337,082	7
Transportation	0	0	180,735	6	2,671,850	31	782,353	27	3,634,938	19
Total	3,958	0.1	380,665	13	3,439,537	40	1,147,860	39	4,972,020	26
<i>All transportation</i>										
Sales	4,850,318	100	2,324,938	77	2,032,233	24	796,521	27	10,034,010	52
Transportation	0	0	706,139	23	6,517,351	76	2,110,284	73	9,333,774	48
Total	4,850,318	100	3,031,077	100	8,579,584	100	2,906,805	100	19,367,784	100

Source: U.S. Department of Energy, Energy Information Administration.

Primary transportation market

The primary transportation market facilitates the initial distribution of transportation contracts. Pipeline companies sell transportation contracts to shippers for prices that are regulated by FERC. Transportation contracts differ primarily in the reliability, timing, and location of natural gas delivery. Shippers purchase transportation contracts in combinations that allow them to achieve the desired service reliability at the minimum cost and to take advantage of time and locational price differentials in the natural gas market.

FERC determines transportation charges using the straight fixed variable rate-making method. Although this method does not yield efficient prices for pipeline transportation, it ensures full cost recovery and provides fair and transparent pricing signals. But increasing competition among interstate pipeline companies has prompted a move toward market-based pricing of transportation services.

Transportation contracts

Deregulation of the U.S. natural gas industry has led to the development of transportation contracts that differ in many dimensions. The most important and frequently used contract dimensions are reliability of transportation service, time and duration of shipment, location of points of injection and withdrawal, pipeline pressure, and charges for pipeline capacity and transportation services.

The contracts most commonly used in the U.S. natural gas industry are of four types (U.S. Department of Energy 1994):

- *Firm transportation contract* — contract that gives its holder the right to pipeline capacity and transportation of natural gas during the entire duration of the contract,

regardless of the season. A firm transportation contract specifies the maximum daily quantity of gas that can be transported through the pipeline, the points of injection and withdrawal, and the charges for reserved capacity and transportation services. The holder of a firm contract may use all or part of the reserved capacity, depending on its needs, but if it exceeds the maximum daily quantity, it will incur a penalty.

- *No-notice firm transportation contract* — contract that gives its holder the right to pipeline capacity and transportation of natural gas under the conditions specified in the contract. The main difference between regular and no-notice firm contracts is that the holder of a no-notice contract is not required to maintain a daily balance between nominated and delivered natural gas (for more information on nominating and balancing natural gas, see the section below on the optimization of pipeline operation).
- *Limited firm transportation contract* — a contract that provides for limited firm service, which is subject to interruption for a specified amount of time each month, for example, up to 10 days a month. This contract is designed to offer less expensive firm service to customers that can tolerate greater risk of delivery interruption and is often used by customers with fuel-switching capability.
- *Interruptible transportation contract* — a contract that gives its holder the right to transport an agreed on volume of natural gas within a certain period. The exact timing of transportation is determined by the pipeline company according to the availability of capacity.

Transportation service reliability These contracts differ primarily in the reliability of transportation services. Firm and no-notice transportation services are the most reliable because shippers' reserved capacity is available to them at all times. (Firm shipments may be interrupted only in extraordinary supply situations caused by forces beyond the pipeline company's control.) Limited firm and interruptible transportation services are less reliable because shippers do not know in advance exactly when an interruption will occur.

Shippers place a premium on firm transportation contracts because such contracts allow them to take advantage of locational price differentials any time they arise. The premium a shipper is willing to pay depends on the probability of congestion and the size of price differentials between two spot markets. If local spot prices of natural gas are high because of congestion in the pipeline system, a shipper with a firm transportation contract can buy lower-priced natural gas in a neighboring spot market and sell it in the congested local market. The shipper's ability to reduce its own cost of natural gas or earn extra profit through locational price arbitrage is reflected in the price of firm transportation services, which tends to be higher than the price of interruptible services.

Shippers seldom need just one level of reliability in transportation services. They typically combine firm and interruptible transportation contracts in a contract portfolio that gives them the minimum acceptable service reliability at the minimum cost. The minimum

acceptable service reliability for a shipper depends on many factors, such as its pattern of natural gas consumption, its ability to substitute natural gas for other fuels, and the structure of its gas contract portfolio. Since shippers have different characteristics, they form different transportation contract portfolios.

Timing of service The timing of transportation services is an important dimension of transportation contracts because shippers must coordinate transportation with natural gas supply. The time structure of transportation contracts has been changing with increasing deregulation of the natural gas market. While traditional long-term supply contracts were matched with long-term transportation contracts, deregulation of gas markets and the increasing use of short-term gas contracts have generated demand for short-term transportation contracts.

Participants in the deregulated gas market seek the flexibility to adjust transportation contracting to natural gas acquisition in order to minimize the total cost of natural gas. They look for short-term transportation contracts that will enable them to take advantage of swings in spot prices of natural gas or to react to unexpected shifts in natural gas supply and demand. The demand for such contracts has been partially satisfied by the introduction of the capacity resale program, but the only satisfactory remedy is a well-functioning transportation market.

Location of intake and offtake points Shippers' ability to choose the location of natural gas delivery is crucial to the efficient functioning of natural gas markets. Shippers respond to locational differences in the spot prices of natural gas by shipping gas to the congested market. If they can use any intake or offtake point on a pipeline where they have reserved capacity, they can eliminate locational price differences along the entire pipeline, resulting in an efficient market.

Deregulation of the U.S. gas markets introduced significant flexibility in delivery locations. Order No. 636 required pipeline companies to offer firm and interruptible shippers a choice in intake and offtake points, based on the priority of locations and the type of transportation service. It also allowed shippers with available reserved capacity to divide this capacity into segments that can be resold separately in the capacity resale market. Both measures have contributed to increasing integration of regional natural gas markets in the United States.

Regulation of the primary transportation market

Interstate pipeline companies are regulated by FERC, which determines rates for interstate pipeline transportation. FERC also establishes rules for the operation of interstate pipeline companies with the aim of promoting the efficient functioning of the interstate pipeline segment and the wholesale natural gas market.

FERC determines tariffs for firm and interruptible transportation services using the straight fixed variable rate-making method, a cost-based price mechanism that uses the average accounting cost pricing concept.¹³ Charges for firm services are divided into a demand charge, which recovers most of the fixed costs of transportation, and a usage charge, which recovers variable (or operational) costs. The demand charge is related to the maximum daily capacity reserved by users, but the greater the reserved capacity, the lower the unit charge. Charges for interruptible services range between maximum and minimum charges. The maximum interruptible charge recovers variable costs and a portion of fixed costs, while the minimum interruptible charge recovers variable costs only.

Fixed costs are allocated between firm and interruptible services on the basis of the ratio of firm to interruptible service loads in the pipeline. The firm load is equal to the total capacity reserved by firm users. The interruptible load is estimated from the expected annual interruptible throughput.

Transportation charges are typically mileage-based, that is, they reflect the average accounting costs of capacity and throughput over a unit of distance. This is the notional path approach to determining charges. Other approaches include zone rates, which set charges equal within a particular geographic area, and postal stamp rates which set flat transportation charges without regard to distance.

Transportation charges also reflect the level of demand uncertainty. Firm service guarantees almost complete reliability, so the charges for such service do not take demand uncertainty into account. For interruptible service, pipelines can provide discounts based on the reliability level, within a range defined by the maximum and minimum interruptible charges.

Transportation charges on newly constructed pipelines are also regulated by FERC. It uses two pricing principles: roll-in rates and incremental rates. If a pipeline company can prove that capacity expansion benefits most of its existing customers, it can “roll in” a portion of the costs of new capacity to all pipeline customers as long as the price increase is no more than 5 percent. If these conditions are not satisfied, the company must use incremental

¹³ The straight fixed variable rate-making method replaced the modified fixed variable rate-making method, which allowed the recovery of certain fixed costs, including a return on equity and related taxes, through a volumetric charge. The change in method in 1992 led to an increase in the unit cost of natural gas for low-load-factor customers and a decline in unit cost for high-load-factor customers. For more details, see U.S. Department of Energy 1995a.

rates that assign the costs of a capacity expansion to the users of the new pipeline (U.S. Department of Energy 1995a).

An evaluation of the straight fixed variable rate-making method The main benefit of the current regulation of transportation charges is that it ensures full recovery of pipeline companies' costs. Other benefits are the transparency and fairness of transportation rates. Pipeline companies regularly report their costs and revenues to FERC, which can determine rates through a relatively simple calculation. All parties involved in transportation can check the results and the methodology. And because all transportation rates are determined using the same methodology, shippers can compare pipeline companies' rates and select the lowest-priced service.

But the economic efficiency of the current price regulation is compromised by FERC's goal of ensuring cost recovery and preventing the exercise of market power exercise by the pipeline companies. The main source of inefficiency is the arbitrary allocation of fixed costs under the average accounting cost pricing concept. The straight fixed variable rate-making method neglects several factors that are important for efficient pricing of transportation: the price and reliability elasticity of demand for transportation services, the marginal cost of capacity and throughput, and demand and supply uncertainty. Because shippers do not pay the actual costs incurred in transporting their shipments, they may make suboptimal decisions about purchasing transportation and natural gas contracts, distorting the allocation of resources in the natural gas industry.

The rate-making method does not give pipeline companies flexibility to charge rates based on demand. With shippers increasingly using short-term firm transportation contracts purchased in the secondary market, the inability to charge demand-based rates threatens full cost recovery. Many low-load-factor shippers find it too expensive to purchase firm transportation contracts at prices determined on the basis of a 100 percent load factor. So they purchase firm contracts for relatively small volumes from pipeline companies and rely on interruptible transportation and the secondary capacity market for additional transportation services needed.

Shippers also are reluctant to enter into long-term transportation contracts because they do not know their market value. Instead, they prefer to purchase short-term transportation contracts, whose market value is revealed in the secondary transportation market. But, short-term contracting for transportation services creates high revenue uncertainty for pipeline companies.¹⁴

¹⁴ Shippers' unwillingness to sign long-term transportation contracts has created serious problems for interstate pipeline companies in the United States. Long-term contracts for about 50 percent of available pipeline capacity will expire by 2002. Although experts expect that about 75 percent of that capacity will be recontracted, pipeline companies will not be able to sell long-term contracts in regions or pipeline corridors with excess capacity. This will expose them to substantial revenue risk unless regulation gives them the flexibility to use price discrimination (McDonnald 1996).

New regulatory measures adopted by FERC FERC has recognized the problems faced by pipeline companies and shippers in the primary transportation market and adopted several measures that expose the interstate pipeline segment to market forces. One of the measures allows pipeline companies to offer discount rate plans, such as seasonal, volumetric, or multipart rates, to low-load shippers.¹⁵ These plans help improve the situation, but they neglect the main source of the problems — the arbitrary allocation of fixed costs under the straight fixed variable rate-making method.

The most important measure has been the establishment of three alternative mechanisms for rate determination (FERC 1996a and 1996b). These mechanisms give pipeline companies the flexibility to customize their rate structures if they can demonstrate that they do not have market power.

- *Market-based rates.* This mechanism allows pipeline companies to charge market-based rates if they do not have market power (the ability to maintain a 10 percent price increase without losing market share) and if they have a Herfindahl-Hirschman index of less than 1,800 (the Herfindahl-Hirschman index measures market concentration for the purposes of an antitrust analysis). Market-based rates are applied case by case.
- *Incentive rates.* This mechanism establishes performance criteria that give pipeline companies an incentive to charge optimal rates even if they have market power. Rates are not cost-based, and no price caps are applied. The efficiency gains are shared by consumers and pipeline companies. The adoption of incentive rates is voluntary.
- *Negotiated rates with recourse to a default rate.* Negotiated rates are determined through mutual agreement between a pipeline company and shippers, while recourse rates are based on cost of service. Shippers have access to both rates. Pipeline companies are required to allocate capacity to recourse shippers during constraint periods, but these shippers will not be solely responsible for the cost of unsubscribed capacity.

The response of the pipeline companies to the proposed rate-making mechanisms has been favorable. Most of the pipelines favor the mechanism of negotiated rates with recourse because it gives them both the certainty of cost recovery under recourse rates and price flexibility under negotiated rates. By October 1, 1996, 13 pipeline companies had filed for approval to use this mechanism. Most of these filings have been approved by FERC (U.S. Department of Energy 1996).

Secondary transportation market

¹⁵ Seasonal rate-making allows pipeline companies to set capacity reservation charges for peak and off-peak seasons. Volumetric rate-making results in a one-part tariff based on the volume of gas delivered. This rate is used mainly by small-volume, low-load-factor customers. Finally, pipelines can use a two-part rate that consists of capacity reservation and usage charges, but allocates fixed costs between the two components (U.S. Department of Energy 1994).

A secondary transportation market is a marketplace where holders of transportation contracts can resell temporarily or permanently unused capacity to other shippers. The first secondary transportation market in the United States, known as the capacity release program, was created by Order No. 636 in 1993. Under this program shippers can purchase transportation contracts from other shippers through a bilateral transaction or an auction. Another secondary transportation market is the gray market, in which shippers use spare capacity to ship natural gas to congested markets.

Capacity release program

The capacity release program established rules for trading firm capacity contracts owned by shippers. Holders of firm transportation or storage contracts can resell them to other parties through a pre-arranged deal or an open bid (U.S. Department of Energy 1995a).

The current holder of a firm capacity contract (the releasing shipper) makes a prearranged deal with the interested party (the replacement shipper) if the capacity release price is equal to the maximum firm rate of the pipeline or if the duration of the contract does not exceed one calendar month. Prearranged deals are concluded bilaterally, through mutual agreement on the conditions of the released capacity contract. Once a prearranged deal is concluded, the details are posted on the pipeline's electronic bulletin board, including the rate charged, the type of charge, the amount of capacity, and the duration of the release (U.S. Department of Energy 199a).

If neither of the conditions above are met, the releasing shipper posts the released capacity along with corresponding conditions in advance on the pipeline's electronic bulletin board. Shippers bid for the contract in an auction, and the highest bidder is awarded the contract. The winning bid price thus becomes the replacement shipper's demand charge. If the bid price is less than the demand charge stated in the contract between the releasing shipper and the pipeline, the releasing shipper must pay the difference. If the bid price exceeds the releasing shipper's demand charge, the releasing shipper keeps the difference. The replacement shipper then negotiates the conditions of transportation services with the pipeline (Herbert 1996b and FERC 1992). Details of the capacity release contract are posted on the electronic bulletin board.

The prices of transportation contracts traded in the capacity release market are regulated by FERC, using the price cap method. The price of released capacity cannot exceed the maximum firm transportation rate of the pipeline company that owns the pipeline system in which the capacity was released.

Activity under the capacity release program The capacity release program has grown dramatically since its start in November 1993. More than 3.2 trillion cubic feet of pipeline capacity was released in the 12 months ending March 31, 1995, and about 5.8 trillion cubic feet, or 59 percent more, was released in the next 12 months. This capacity represented about 15 percent of the total end use consumption of natural gas in 1994 and 30 percent in 1995. More capacity is released in the nonheating season than in the heating

season. In the 1995 nonheating season 3.3 trillion cubic feet of capacity was released, and in the 1995-96 heating season about 2.4 trillion cubic feet of capacity was released.

The prices for capacity have been well below the price cap, but they are gradually increasing. The average rate for released capacity was discounted 65 percent from the maximum transportation rate during the 1995-96 heating season and 83 percent during the 1995 nonheating season. These rates reflect a substantial increase from the 82 percent discount in the 1994-95 heating season and the 92 percent discount in the 1994 nonheating season. On average, released capacity seems to be an inexpensive substitute for primary transportation contracts.

An evaluation of the capacity release program The capacity release program is potentially an effective tool for promoting efficient allocation of pipeline capacity among shippers. Since shippers are allowed to trade unused capacity among themselves, no unused capacity should be left after the market clears. Shippers that value capacity the most buy it from shippers that value it little because they do not intend to use it. Shippers sell capacity for a price that reflects its opportunity cost and makes both buyer and seller better off. The allocation of capacity among shippers on the basis of their willingness to pay should lead to efficient allocation of resources and greater utilization of pipelines.

One of the most important conditions for the efficient allocation of capacity, however, is market pricing. Since capacity release is increasingly used for resale of short-term capacity,¹⁶ the price of released capacity should follow the short-run marginal cost of capacity, falling in off-peak periods and rising in peak periods to reflect changes in the opportunity cost.

But the price cap imposed by FERC, which prevents the market price of released capacity from exceeding the maximum firm rate, leads to distorted prices and thus inefficient allocation of capacity. Shippers unable to obtain market value for their unused capacity will be unwilling to sell it through the capacity release program. The distorted prices for the transactions that do take place give buying shippers inefficient signals about the market value of released capacity and attract more than the efficient level of demand.

The price cap allows efficient pricing of released capacity only in off-peak periods, when pipeline systems are not congested. In these periods the opportunity cost of capacity is well below the price cap, and shippers pay a price determined by the market. Since the capacity resale market is relatively competitive,¹⁷ particularly on major transportation routes, capacity prices in off-peak periods are relatively efficient and promote efficient allocation.

¹⁶ About 90 percent of capacity released since the start of the program on November 1, 1993, became available to shippers within two weeks from the date of contract award. And more than 70 percent of released capacity in the 1995-96 heating season was under contracts for terms of 31 days or less (U.S. Department of Energy 1996).

¹⁷ On average, shippers can potentially obtain capacity from 70 holders of firm contracts on a given pipeline (De Vany and Walls 1993).

The relatively low average price of released capacity has made the price cap nonbinding on average. But because the price of released capacity cannot exceed the price cap and because prices are low in off-peak periods, the average price necessarily is less than the price cap. The explanation may also be that there is an abundance of pipeline capacity or that capacity resale in peak periods takes place outside the capacity release program. The existence of the gray market suggests that the second is true.

Another problem, particularly in the resale of short-term firm contracts, is the high transaction costs of capacity resale. Shippers require flexibility in contracting in order to be able to react quickly to changes in the market. The auctioning of capacity, which requires posting and bidding, does not provide the required flexibility. Shippers must go through several (sometimes incompatible) electronic bulletin boards to acquire information about available capacity and complete transactions with other shippers. These problems have led shippers to resell firm contracts mainly through bilateral prearranged deals. Under Order No. 577, prearranged capacity release deals with a term of up to one calendar month are exempt from the advance posting and bidding requirements.

FERC has also taken other measures to address problems in the capacity release program. It has pushed the industry to standardize electronic bulletin boards and capacity release procedures to reduce the transaction costs of capacity resale. In 1996 it issued Order No. 587 requiring all pipeline companies to establish procedures to speed the process of capacity release. And most recently, it proposed removing price caps on released capacity if the releasing shippers can demonstrate that they do not exercise market power. This proposal is being studied by the industry.

Gray market

The gray market represents a market solution to the distortive regulation of capacity release prices. The market facilitates the trading of pipeline capacity bundled with natural gas and sold in congested markets. Shippers with firm capacity rights can earn the market value for their temporarily or permanently available capacity by using it to ship natural gas to congested markets. Since the price of natural gas is not regulated, shippers can charge the price that maximizes their profits.

The evolution of the gray market can be traced to the period before Order No. 636, which allowed the resale of transportation contracts. Local distribution companies, the most frequent holders of firm capacity, used their temporarily available capacity to ship natural gas to city gates on behalf of third parties, charging them regulated prices, under “buy-sell” contracts. Order No. 636 prohibited new buy-sell contracting but did not abolish existing contracts, even after deregulation of natural gas prices. This allowed local distribution companies to continue shipping natural gas to city gates on behalf of third parties and, more important, selling it for unregulated prices (Marston 1994).

Despite the attractiveness of unregulated market pricing, the gray market is neither a substitute for capacity release nor an efficient market for pipeline capacity. Gray market prices barely reflect the system marginal costs of natural gas and pipeline capacity because trading is thin compared with activity in the overall natural gas market. Transaction costs are relatively high, because there is a lack of information about available capacity, market prices, and the like. Buyers also face the monopoly power of sellers that control bottleneck capacity. So the gray market is beneficial because it allows transactions that otherwise would not occur, but it suffers from high transaction costs and monopoly power.

FERC will have to address these problems in order to optimize secondary trading and allocation of pipeline capacity. Its recent measures to simplify the capacity release program and allow market pricing of released capacity in competitive markets will certainly attract some gray market players to the capacity release program. But the gray market will probably continue to exist until regulated prices for released capacity become nonbinding.

Optimization of Pipeline Operation in the Unbundled Natural Gas Industry

Transactions in a deregulated natural gas industry must be coordinated to achieve simultaneous clearing of natural gas and transportation markets at the minimum total cost. Market participants in the U.S. natural gas industry match the available supply of natural gas and transportation contracts with their demand through decentralized bilateral transactions. Each market participant minimizes its own costs of natural gas and transportation. But the total costs of natural gas to end users may not be minimized if transportation is inefficient because of suboptimal operation of pipelines.

An interstate pipeline company in the United States faces demand for transportation services that consists of the demand of many individual shippers. The utilization of its pipeline capacity varies because of the frequently changing volume of individual shipments. To maximize the utilization of pipelines and minimize the total cost of transportation, a pipeline company uses its available capacity for interruptible services. As a result, a typical pipeline is used by several shippers at once. Since the load for one shipper is dependent on the loads of others, an action by one shipper can impose substantial costs on the others and on the entire pipeline system. To minimize the total cost of pipeline transportation, all shippers must therefore obey a set of common rules that coordinate shipments in the pipeline system.

Optimal pipeline operation is achieved through scheduling, balancing, central dispatch, and emergency control of gas flows in the pipeline system. Scheduling and balancing are means to coordinate natural gas supply with transportation services. A pipeline company carries out these activities by acquiring information about the volumes of gas and the pipeline capacity demanded by shippers, then determining the flow of shipments through the pipeline system that minimizes transportation costs and satisfies shippers' demands. Central dispatch and emergency control maintain system balance and guide gas flows through the pipeline system in real time.

Scheduling and balancing

Scheduling is the process of determining of the optimal flow schedule — the order and direction of gas flows in the pipeline system that minimize the total cost of transportation. Balancing is the process of maintaining and restoring the balance of the pipeline system (system balance) and individual shipments (shipper's balance).

Pipeline companies determine the optimal flow schedule based on information about demand for transportation services. Scheduling and balancing can be broken down into the following stages:

- Shippers “nominate” daily volumes of natural gas to be delivered, received, or stored by the pipeline company on the upcoming gas day (a period of 24 hours that is used in pipeline transportation). Nominations must be submitted in writing or electronically by a certain time on the day preceding the gas day. Shippers also nominate capacity at

specific intake or offtake points. Nominations of daily volumes can be renewed or changed on a monthly basis and may specify any quantity up to the maximum daily quantity specified in the transportation contract.

- A pipeline company aggregates the gas and capacity nominations and determines whether the pipeline system can match the total nominated capacity and gas volumes. Then it confirms the nominations or asks for adjustments.
- The pipeline determines the schedule of all gas flows into and out of each receipt and delivery point. The flows are scheduled according to priorities determined by the type of transportation contracts involved.
- Shippers inject or withdraw natural gas and are responsible for keeping the difference between actual and nominated gas volumes within the agreed on tolerance levels (5 to 10 percent of nominated volume, but flows should not exceed the maximum daily quantity). Balancing is performed both daily and monthly. Negative imbalances — those occurring when a shipper withdraws more gas than it injects — are subject to penalties.

The balancing of natural gas flows is aided by the following tools and services:

- *Operational balance agreements.* Under an operational balance agreement, the operators of interconnecting pipelines resolve monthly imbalances among multiple shippers, so that individual shippers do not incur an imbalance penalty. Such agreements promote the integration of pipeline systems because they allow pipeline companies to settle imbalances with other connecting pipeline or distribution companies rather than with each customer.
- *Overrun authorizations.* An overrun authorization allows a shipper to transport more than the maximum daily quantity of natural gas, subject to prior approval by the pipeline company.
- *Penalties.* Penalties are used to discourage shippers from running an imbalance in their shipments. There are three types of penalties:¹⁸
 - Scheduling variance penalties — incurred when the daily flow of natural gas does not match the nominated flow.
 - Overrun penalties — incurred when the shipper's maximum daily quantity is exceeded.
 - Imbalance penalties — incurred when the total monthly receipts into the pipeline do not match the total monthly deliveries to the shipper.
- *Market center services*
 - No-notice service. Under no-notice service, a shipper may exceed its daily nomination without incurring scheduling penalties, but it must not exceed the maximum daily quantity.

¹⁸ For more information on penalties, see U.S. Department of Energy 1994.

- Lending and parking services. Lending is a short-term storage service to deliver natural gas to a shipper when it needs more than its nominated volume. Parking is short-term storage for a shipper when it needs less than its nominated volume.
- Wheeling service. Wheeling gives customers the ability to change a delivery point by arranging delivery to an alternative location.

Gas flow control in real time

Pipeline companies must have the ability to control and direct flows of natural gas through the pipeline system in real time in order to maintain system balance in the event of an unexpected disruption of gas flows. There are three major tools for controlling and directing natural gas flows:

- *Central dispatch.* Central dispatch directs flows of natural gas through the pipeline system according to a predetermined flow schedule and an emergency plan. Central dispatch is performed by a pipeline's gas control unit, which has electronic devices to monitor and control the direction of flows and the volume and pressure in the pipeline system and interconnected storage facilities.
- *Operational flow orders.* These are emergency orders issued by pipeline companies that require shippers to inject or withdraw natural gas at a specific point to ensure continued flow of natural gas through the system. Operational flow orders are used only in emergencies, and shippers must be notified several hours before such an order is implemented.
- *Curtailments.* Under curtailments, pipeline companies may cut off transportation or storage service to shippers in the event of a major supply or capacity disruption. Curtailments are used primarily in the most severe emergencies. A priority order for curtailments is determined by a pipeline company and approved by FERC. Firm transportation is the last service disconnected.

Conclusion

Deregulation of the U.S. natural gas industry has shown that market forces can result in efficient transactions in industry segments traditionally considered natural monopolies. The main goal of deregulation was to create competitive markets in natural gas and pipeline transportation, in the expectation that competition would guide individual transactions toward the socially optimal outcome.

The achievements of the U.S. gas industry in the past 15 years confirm the overall direction of deregulation. The United States enjoys a highly competitive wholesale natural gas market and an increasingly competitive interstate transportation market. Both markets have benefited from deregulation of natural gas production and marketing and liberalization of natural gas prices. And the introduction of open access to interstate

pipelines and their unbundling from gas sales have allowed end users to participate in the efficiency gains in upstream markets. All this has contributed to declining retail prices for all major consumer categories.

But deregulation is far from complete. The current regulation of interstate pipeline companies and the secondary transportation market does not promote efficient allocation of transportation contracts. Flexible pricing of transportation contracts should be introduced in both the primary and the secondary transportation market. But deregulation of retail markets remains the most important task and the biggest challenge for industry regulators. Small-volume end users, such as residential or commercial customers, are captive to local distribution utilities and cannot access competitive wholesale markets. All end users should be able to choose a natural gas supplier and receive natural gas at the minimum cost to society.

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