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Preface

Natural Gas 1994: Issues and Trends has been prepared by the Energy Information Administration (EIA) to provide a summary of the latest data and information relating to the natural gas industry, including production, consumption, markets, and prices. The report also examines several aspects of the structural changes taking place as the natural gas industry responds to recent regulatory and legislative changes.

The report consists of five chapters and three appendices. Each chapter is designed to be self contained, resulting in some repetition of definitions and other background material. Chapter 1 reviews recent data on natural gas prices, consumption, and supply, examining recent trends in drilling and production, total system deliverability, and end-use markets. Future prospects for the industry are also discussed. (Text notes appear at the end of this chapter because of the two-page subject format.) Chapter 2 discusses the response of the interstate pipeline companies to the restructuring requirements of Order 636. Chapter 3 looks at natural gas supply and transportation contracts, and includes basic examples of the use of financial instruments within the natural gas industry. Chapter 4 analyzes the underground natural gas storage market, examining the increased use of storage by the industry. Chapter 5 reviews the effects of developing new market structures on the financial performance of the natural gas industry.

The three appendices provide supplemental information to support the discussion and analysis presented in the body of the report: Appendix A summarizes current Federal Energy Regulation Commission (FERC) policy initiatives, FERC Order 636, and environmental and safety developments applicable to the industry; Appendix B provides numerical examples of how interstate pipeline firm and interruptible transportation rates are developed; Appendix C presents the methodology used to estimate the measures of financial performance presented in Chapter 5.

Unless otherwise stated, historical data through 1992 on natural gas production, consumption, and price come from EIA, *Natural Gas Annual 1992*, Vol. 1 and 2, DOE/EIA-0131(92)/1 and 2 (Washington, DC, November 1993). Similar annual data for 1993 and monthly data for 1993 and 1994 come from EIA, *Natural Gas Monthly* (*NGM*), DOE/EIA-0130 (94/04) (Washington, DC, April 1994). Data from the *NGM* are preliminary estimates.

This report is the second *Natural Gas: Issues and Trends*. (There is no 1993 volume). A prepublication release of the Executive Summary was distributed in May 1994. However, the reader should note that updated information on stock market results has been incorporated into this report, which resulted in revisions to the Executive Summary, specifically, Figure ES5 and corresponding text.

Contents

Page

Executive Summary ix

1. Overview 1
Natural Gas Supply 3
Changing Market Dynamics 11
Deliverability 19
End Use 27
Outlook 31

2. The Natural Gas Industry Under Order 636 37
Introduction 37
New Services, New Corporate Structures 37
Managing and Operating the New System 40
Transportation Capacity Can Now Be Traded 43
Transportation Rates Are Evolving 46
Outlook 54

3. Natural Gas Contracting 55
Natural Gas Supply Contracts 57
Natural Gas Transportation Contracts 67
The Portfolio Decision 72
Outlook 76

4. The Natural Gas Storage Market 79
The Operation of the Storage Market Today 80
New Market Requirements Are Driving Storage Expansions 86
Outlook 95

5. Financial Aspects of the Natural Gas Industry 97
Introduction 97
Overall Financial Performance of the Industry 98
Financial Performance of the Industry Segments 104
Outlook 120

Appendices
A. Regulation and Legislation 125
B. Transportation Rates Under Order 636 141
C. Financial Analysis Methodology 153

Tables

1. Competition and New Opportunities Also Carry Risks . . . 16
2. Corporate Restructuring in the Post-636 Market . . . 41
3. Characteristics of Monetary Penalties . . . 43
4. Selected Pipeline Company Post-636 Transportation Rates and Costs . . . 48
5. Cost Recovery Under the Natural Gas Act . . . 51
6. Impact of Order 636 on Transportation Rates . . . 53
7. Features of Financial Instruments . . . 63
8. Working Gas Storage Capacity and Daily Deliverability, by Type of Site and Operation, As of December 31, 1993 . . . 83
9. Monthly Natural Gas Injections, Withdrawals, and Working Gas Levels, Heating Years 1983-87 Versus 1988-1992 . . . 84
10. Proposed New and Expansion Underground Storage Projects in the United States, 1994-1999 . . . 91
11. Regional Underground Storage and Peak-Shaving Capacity Relative to Pipeline Capacity and Peak Month Production/Consumption . . . 95
12. Industry Segment Financial Highlights, 1992 and 1993 . . . 102
13. Factors Influencing the Financial Performance of Producers . . . 107
14. Factors Influencing the Financial Performance of Natural Gas Marketers . . . 110
15. Recent Examples of Marketing Industry Consolidation . . . 111
16. Factors Influencing the Financial Performance of Interstate Pipeline Companies . . . 114
17. Factors Influencing the Financial Performance of Local Distribution Companies . . . 118
18. LDC's Shoulder Greater Risks . . . 119

Figures

1. Gas Supplies Move into Balance . . . 2
2. Technological Advances Enhance Supply . . . 4
3. North American Gas Trade Continues to Expand but at a Slower Pace . . . 6
4. North America Has Vast Natural Gas Resources . . . 8
5. Wellhead, Spot, and Futures Prices Were Higher in 1993 . . . 10
6. The Use of Natural Gas Futures Grows Dramatically . . . 12
7. Changing Market Dynamics . . . 14
8. Peak Demand Drives Deliverability Requirements . . . 18
9. Pipeline Capacity Increases in Major Markets . . . 20
10. Storage Is a Key Factor in Meeting Peak Demand . . . 22
11. Total System Deliverability Can Support Market Growth . . . 24
12. End-Use Consumption and Prices Increased in 1993 . . . 26
13. Future Trends in End-Use Markets . . . 28
14. Outlook . . . 30
15. Diversity of Natural Gas Services . . . 38
16. Estimated Transition Costs of the Pipeline Industry . . . 50
17. Average Natural Gas Wellhead Prices by Month, 1984-1993 . . . 57
18. Deliveries of Natural Gas by Month, May 1990 - March 1994 . . . 61
19. Participation in the Natural Gas Futures Market by Industry Segment, 1993 . . . 66
20. Transportation Penalties: Incurrence and Avoidance . . . 69
21. Natural Gas Contracting Paths . . . 70
22. Working Gas Levels as a Percentage of Working Gas Capacity During Nonheating Seasons, 1990-1993 . . . 84
23. Withdrawals from Underground Natural Gas Storage During Heating Seasons, 1985-86 Through 1992-93 . . . 85
24. Salt Cavern Withdrawals as a Share of Total Natural Gas Storage Withdrawals, Heating Years 1989-1993 . . . 87
25. Salt Cavern Withdrawals as a Share of All Other Withdrawals . . . 87
26. Projected Working Gas Capacity for New and Expansion Projects by Development Cost . . . 91
27. Estimated Annual Cost of Service for Proposed Storage Projects Under Several Cycling Scenarios . . . 93
28. Working Gas Capacity by Region, 1993 and Proposed Additions, 1994-1999 . . . 96
29. Percent Changes in Monthly Wellhead Prices, 1985-1993 . . . 100
30. The Regulatory-Market Continuum Within the Natural Gas Industry . . . 100
31. Stock Price Index . . . 102
32. Average S&P Bond Ratings . . . 103
33. Rates of Return . . . 104
34. Average Market/Book (MB) Value . . . 104
35. Estimated Gross Revenues from Lower 48 States Oil and Gas Production . . . 106
36. Lower 48 States Oil and Gas Production . . . 106
37. Marketer Share of Total Deliveries . . . 109
38. Allowed Versus Actual Pipeline Company Rates of Return . . . 115

Executive Summary

Operating in the wake of almost continuous regulatory change during the past 15 years, the natural gas industry has been successfully adapting to institutional restructuring and significant market changes. The industry completed the restructuring mandated under the Federal Energy Regulatory Commission's Order 636 in time for the 1993-94 heating season and was quickly tested by severe weather in January 1994. Initial concern about the operation of the gas network was substantially allayed when the system delivered record amounts of gas to the eastern half of the country during extreme weather. The industry has also responded to some dramatic changes in market conditions, streamlining and improving the efficiency of operations. Faced with a 51-percent decline in real wellhead prices from 1984 through 1992, producers have reassessed drilling and production activities with the result that the "bubble" of oversupply that had plagued the industry since the mid-1980's has virtually disappeared, leaving supply and demand essentially in balance.

This report provides an overview of the natural gas industry in 1993 and early 1994 (Chapter 1), focusing on the overall ability to deliver gas under the new regulatory mandates of Order 636. In addition, the report highlights a range of issues affecting the industry, including:

- Restructuring under Order 636 (Chapter 2)
- Adjustments in natural gas contracting (Chapter 3)
- Increased use of underground storage (Chapter 4)
- Effects of the new market on the financial performance of the industry (Chapter 5)
- Continued impacts of major regulatory and legislative changes on the natural gas market (Appendix A).

Highlights

1993 in Review

There are indications that industry operations became more efficient in 1993 as the market adjusted to increased operational and contractual flexibility. There was a moderation in some seasonal aspects of the market, with indications that this reduced seasonality will continue.

- **The March 1993 "Storm of the Century" was eclipsed by the frigid weather in January 1994.** The winter of 1992-93 ended the pattern of warmer-than-normal weather during the previous three winters. This sparked a 5-percent increase in combined residential and commercial consumption in 1993. Approximately half of this increase was directly attributable to the March 1993 storm that swept across the eastern part of the Nation. This was the highest level of March consumption since monthly data have been collected (beginning in 1973). Less than a year later, in January 1994, a week that was 40 percent colder than normal for much of the East Coast provided a more severe test of the industry. Deliveries to residential and commercial consumers in January 1994 were up 18 and 30 percent, respectively, from the previous year and also were the highest monthly levels recorded since 1973. This resulted in near-record pipeline throughput, storage withdrawals, and gas send-outs by local distribution companies.

- **Wellhead prices moved higher in 1993 for the second year as surplus wellhead deliverability declined and markets moved into better balance.** Between 1991 and 1993, average annual wellhead prices increased by 21 percent. Much of the increase occurred in 1993, as wellhead prices averaged $1.99 per thousand cubic feet, an increase of 14 percent from 1992. Average annual wellhead capacity utilization in 1993 is estimated to be 81 percent, a substantial improvement from the 67-percent utilization in 1985. The rising gas prices in 1992 led to a drilling recovery that continued in 1993. Gas well completions in 1993 increased by 11 percent. This turn-around in drilling combined with higher gas finding rates is expected to allow the industry to maintain adequate supplies of natural gas.

- **Natural gas production rose 3 percent in 1993 to 18.3 trillion cubic feet, a continuation of the upward trend seen since 1986.** Increased production has tended to be concentrated in the traditionally off-peak summer months and largely dedicated to the injection of gas into storage for winter use, as well as to meet incremental demand from electric utilities and industrial cogenerators. Consequently, seasonality in production has been reduced, with less variation in production flows throughout the year.

- **A striking development during 1993 was the absence of a strong seasonal pattern in average wellhead prices.** Instead of the usual decline in late spring, prices in May reached their highest level of the year. Many factors, such as the late spring storm, contributed to this unusual price pattern. However, there are indications that the reduction in seasonality in wellhead prices may continue into 1995. For example, the futures contract prices in 1994 (as of March 17) show a moderated seasonal pattern with a winter peak, but no significant trough in the off-peak months when compared with futures prices a year earlier. While seasonal price differentials appear to have declined, prices are expected to exhibit continued variability as a result of unanticipated supply and demand conditions, such as those caused by unusual weather patterns.

- **A heightened role for storage in the current market is becoming increasingly evident.** The reduction in wellhead price seasonality can, in part, be attributed to the increased utilization of storage. For example, from 1988 through 1992, storage injections and withdrawals averaged 20 percent and 18 percent higher, respectively, than during the previous 5-year period. In addition, inventory levels are being more closely monitored. Lower inventories and increased injection and withdrawal activities may indicate a fundamental adjustment relating to the economics of storage use and a reassessment of the storage levels needed for supply reliability. Despite the lowest levels of working gas since 1978 going into the last heating season, storage performed well in meeting the extraordinary demands placed on the system during January 1994.
- **North American gas trade is a major factor in today's competitive market.** Imports no longer serve as a marginal source of supply, but are actively competing for market share. From 1992 to 1993, imports increased by 6 percent to 2.3 trillion cubic feet, and provided 11 percent of domestic consumption. Import capacity from Canada increased by 24 percent, or 1.8 billion cubic feet per day, during 1993 with the completion of several major projects. In addition, plans have been announced for another 1.3 billion cubic feet per day of import capacity by 1996. Although no significant changes in gas trade with Mexico are expected in the near term, the North American Free Trade Agreement, enacted in December 1993, will help foster the development and integration of the Mexican gas industry.

The Industry Adjusts to a New Way of Doing Business

The separation of the merchant and transportation functions of interstate pipeline companies under Order 636 has vastly increased the choices that pipeline company customers have for obtaining service. In turn, the restructuring has also greatly increased the complexity of contracting for natural gas service. As the gas industry entered its first heating season under the new regulatory system in November 1993, two facts were immediately apparent: competition in gas marketing was intensifying, and the responsibility of guaranteeing supply security had shifted from pipeline companies to marketers, local distribution companies (LDC's), and end users.

- **These changes have resulted in a new menu of services and options available to industry players.** Some of these services, such as gathering, storage, and system balancing, were typically included as part of the bundled service provided by pipeline companies. Other financial and risk management services have been developed in response to the increased market risks facing customers. New service selections make it easier for end users to make tradeoffs between the quality of service they want and the price they are willing to pay.

- **New transportation flexibility allows customers to reduce the cost of moving gas.** The development of market hubs and creation of a secondary market for released capacity are new aspects of the market, providing improved access to supply areas and new transportation routes. The value of these new options is greatly enhanced by the electronic bulletin boards being used to trade capacity.

- **Planned storage expansions could increase peak-day deliverability from underground storage facilities by 27 percent by the end of the decade.** More than two-thirds of the 18-billion-cubic-foot-per-day increase is expected from "high-deliverability" facilities, such as salt cavern storage, where gas can be injected and withdrawn on a continuing basis throughout the year to balance daily or monthly demands. In addition, many of the planned new storage sites are in proximity to major market hubs. As the number and variety of contractual arrangements have increased in the market, storage will be used to adjust for system imbalances, provide emergency supply backup, and support the new "no-notice" service required under Order 636.

- **Risk management is an important element of the industry today.** Mechanisms for managing price risk, such as futures contracts and other related financial instruments, have become widely available to market participants. The number of gas futures contracts (open interest) doubled between January and May 1993, reaching more than 140,000 contracts. Strategies are also available to manage other types of risk, such as supply risk. For many gas market participants, the challenge now is to evaluate the risks they face in order to develop an overall risk management strategy.

A Very Competitive Market Offers Significant Opportunities

Natural gas consumption is expected to expand by 2 trillion cubic feet by the year 2000. Much of the growth will be driven by environmental considerations as well as the increased competitiveness in natural gas markets. Recent growth has been dominated by cogeneration applications in the industrial sector and weather-induced increases in the residential sector. Future growth will be concentrated in electricity generation by industrial and commercial cogenerators, as well as electric utilities and other nonutility power producers.

- **Gas demand for electric utility generation will grow largely because of economic and environmental advantages of natural gas over other generating fuels.** The majority of new generating facilities built by electric utilities are expected to be gas-fired, primarily combined-cycle plants and combustion turbines. These units are more efficient, less capital-intensive, available in a wide range of capacities, and can be constructed more quickly than alternative units. In addition, natural gas is a clean-burning fuel and therefore an important component in reducing emissions and improving air quality. Approximately 60 percent of planned generating capacity additions through 2000 are expected to be gas-fired.

- **A potentially significant market is electric utility repowering projects, which upgrade existing gas-fired powerplants and convert oil- and coal-fired plants to natural gas or co-firing capability.** Repowering has an advantage over new construction in that it involves fewer permit approvals, shorter lead times, and may have lower construction costs. A plant can often be repowered at higher capacity and higher efficiency than the original design. Although utilities have reported only a few planned repowering projects, by some industry estimates, as much as half of the growth in gas consumed in the electric power sector could come from repowered units over the longer term.

- **Retail natural gas prices are projected to remain competitive with petroleum prices, increasing (in real terms) by 2.5 percent per year on average from 1992 through 2000.** This projection shows that competition in the electricity sector between natural gas and residual fuel oil will continue to be a limiting factor for natural gas price increases. However, if the primary competitor of natural gas becomes distillate fuel oil, rather than residual oil, there would be opportunity for upward movement in the market price of natural gas, depending on the intensity of competition within the gas industry.

Outlook for the Industry

The expanding natural gas market and more competitive environment will provide companies in all sectors of the industry with new possibilities to improve their financial performance. However, success will depend on management's ability to take advantage of the new opportunities—for example, instituting more flexible operations, reducing costs, and finding and developing the markets they can serve best. On the other hand, the increased complexity of the market requires much closer attention to contracting arrangements, risk management, and the use of electronic information transfer.

- **Recent trends in stock prices and bond ratings support a cautious optimism regarding the financial prospects for the natural gas industry.** Stock prices for most segments of the industry outperformed the Standard and Poor's 500 index during 1993. However, gains in the early part of the year were partly offset by fourth quarter declines, when stock prices for all segments of the industry declined (3 to 18 percent), while the S&P 500 rose slightly (1 percent). Results for the first quarter of 1994 were mixed. Prices generally rose in January because of record activity associated with the colder-than-normal weather. However, stock prices declined after February because of successive increases in interest rates, continued low oil prices, uncertainty regarding gas prices, and expectations of lower allowed rates of return for pipeline companies and LDC's. Bond ratings in 1993 were stable but substandard for a sample of independent producers and interstate pipeline companies.

- **The future financial performance of individual companies will reflect their ability to exploit new opportunities.** For producers, the key will be finding and developing new gas reserves at competitive prices. The outlook for marketers will depend on the extent to which they can capitalize on the access provided by market hubs to serve a wider regional mix of clients and to provide rebundled services to customers who prefer "one-stop shopping." The financial performance of pipeline companies now depends mainly on their role as gas transporters and will hinge on their ability to sell capacity. For LDC's, key financial considerations are the management of new responsibilities for gas supply and transportation, reducing costs, and developing new markets for their services.

The opportunities available to the industry today are substantial. The new structure that has evolved under Order 636 has placed the natural gas market in a better position to compete in the current energy market. The financial performance of participants in the natural gas industry will be determined by their ability to adapt to the new business environment, maintain competitive prices, and provide reliable service.

1. Overview

In 1993, the natural gas industry and its customers experienced a smooth transition to a new operating environment, even though they faced fundamental adjustments in the market. Two events in particular affected all segments of the market:

- The interstate pipeline industry was restructured in accordance with Federal Energy Regulatory Commission (FERC) Order 636.

- The excess productive capacity that had characterized the industry throughout the 1980's diminished, leaving supply and demand in better balance.

As a result of these developments, all segments of the industry are facing increased competition, some segments are facing higher risks, gas prices have risen, and a renewed emphasis has been placed on gas exploration, production, and delivery.

FERC Order 636, issued in April 1992, required interstate pipeline companies to separate (or "unbundle") all of their services. Gas purchases are essentially free from regulation, while transportation and storage remain subject to FERC jurisdiction. However, more competition has been introduced into the gas transportation industry with the establishment of a secondary market in pipeline transportation. The secondary market permits pipeline company customers to trade capacity rights among themselves, using electronic bulletin boards provided by the pipeline companies.

In November 1993, the gas industry entered its first heating season under the new regulatory system. Two facts were immediately apparent: competition in gas marketing was intensifying, and the responsibility for guaranteeing supply security had shifted from pipeline companies to marketers, local distribution companies (LDC's), and end users themselves. Concern about the operation of the gas network was substantially allayed in January 1994 when the system delivered record amounts of gas to the eastern half of the country during a severe cold spell.

This chapter reviews the major events affecting the natural gas industry in 1993 and early 1994 and provides a historical context for interpreting their impact in the near term. The themes of *competition* and *risk* recur throughout this chapter, and the rest of the document, and are discussed from many perspectives.

- Competition—particularly how it has led to the development of new services. Order 636 restructuring has provided the industry with many alternatives for managing the purchase and transportation of natural gas. Customers now require services that had previously been part of their bundled service arrangements with pipeline companies. In addition, financial services are an increasingly important aspect of contractual arrangements as regulatory guidelines and controls have been removed from many aspects of the marketplace.

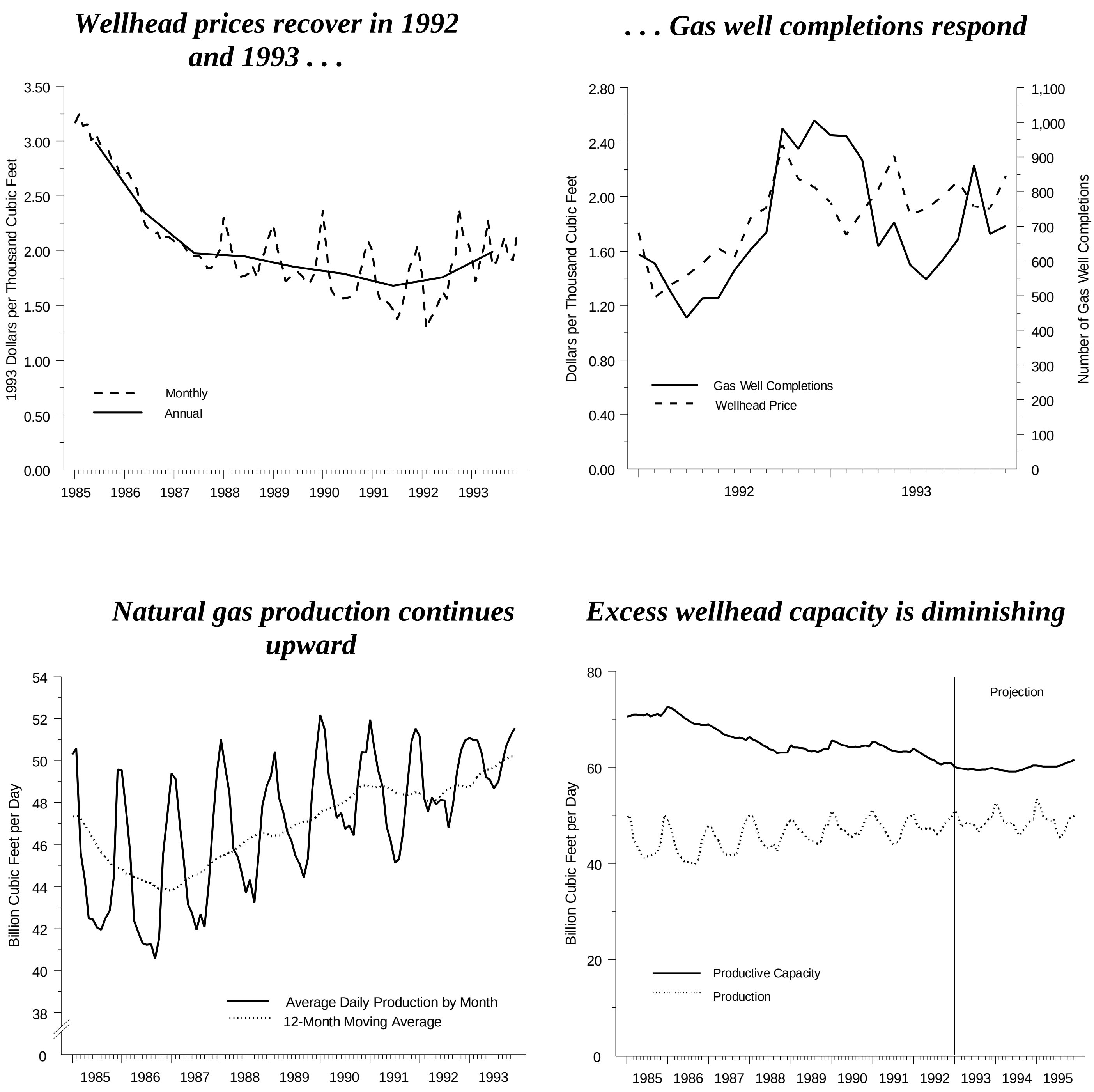
- Risk—how it has changed for industry participants, and how the industry is adopting strategies to manage that risk and benefit from the opportunities that accompany it.

Chapter 1 first examines changes in the supply side of the industry—drilling, production, imports, and prices—and the closer balance between supply and demand that has recently developed. The chapter next highlights how the new regulatory environment has changed industry operations and the dynamics of the market. Overall system deliverability is then addressed, illustrating how the industry uses many supplemental sources of supply to meet peak-period demand such as that experienced in January 1994. The chapter also presents recent developments in end-use markets and identifies the growth areas that are expected to shape the industry in the future. Finally, the historical perspective is summarized and future prospects for the industry are discussed. (Text notes for Chapter 1 appear at the end of the chapter.)

Subsequent chapters and appendices highlight a range of issues affecting the industry.

- Restructuring under Order 636 (Chapter 2 and Appendix B)
- Adjustments in natural gas contracting (Chapter 3)
- Increased use of underground storage (Chapter 4)
- Effects of the new market on the financial performance of the industry (Chapter 5 and Appendix C)
- Major regulatory and legislative changes and how they continue to shape the natural gas market (Appendix A).

Figure 1. Gas Supplies Move into Balance



Note: Wellhead prices were converted to 1993 dollars using annual and monthly producer price indices.

Sources: Energy Information Administration. **Wellhead Prices and Production:** 1985-1988—*Historical Monthly Energy Review, 1973-1988*. 1989—*Natural Gas Monthly*, March 1992. 1990—*Natural Gas Monthly*, March 1993. 1991—*Natural Gas Monthly*, March 1994. 1992-1993—*Natural Gas Monthly*, April 1994. **Well Completions:** *Monthly Energy Review*, April 1994. **Productive Capacity and Production**: 1985-1992—*Natural Gas Productive Capacity for the Lower 48 States: 1982 through 1993*, 1993-1995—"Natural Gas Productive Capacity for the Lower 48 States: 1980 through 1995," draft report.

Natural Gas Supply: Exploration and Production

After a decade of excess productive capacity, gas supplies continued to move into closer balance with demand during 1993. This can be attributed largely to the improved price signals producers now receive. Clear price signals are a result of industry restructuring and the abolition of price controls that encouraged drilling even in the presence of excess productive capacity.[1] Indicative of the better balance between supply and demand, idle capacity has declined significantly. In December 1985, over 30 percent of the Nation's natural gas productive capacity lay idle, clearly more than the industry's operational needs. For December 1993, idle capacity is estimated at a more efficient 17 percent—adequate, with deliverability from storage, to meet peak demands.

- **Reflecting the improvement in price signals, changes in wellhead prices for natural gas had a swift and robust impact on drilling levels in 1993.** Rising gas prices in 1992 led to a drilling recovery that continued into 1993 (Figure 1). Well completions continued at a brisk pace for the first quarter of 1993, averaging 939 per month. Amid uncertainty over prices, completions declined to 648 per month in the second quarter and 604 in the third quarter. Completions rose to 876 in October only to decline to 702 in December as natural gas wellhead prices softened in response to the plunge in oil prices. Annual completions were 11 percent higher than in 1992, although still low when compared with historical levels. Nevertheless, gas well completions surpassed oil well completions for the first time. As recently as 1987 the number of gas well completions was less than half the number of oil well completions.

- **Reflecting improved productivity, reserve additions have been buoyed by higher finding rates and positive reserve revisions.** Gas discoveries per successful gas exploratory well increased from 6.7 billion cubic feet (Bcf) in 1982 to 21.4 Bcf in 1992 (the latest year for which data are available). Industry restructuring, improvements in technology, and a strategy of focusing on larger prospects have led to significant improvements in the efficiency of finding new reserves of natural gas. In 1992, reserve revisions resulting from new information about known gas reservoirs accounted for 46 percent of total gas additions. As a result of these factors, the industry was able to add almost as much to reserves in 1992 as in 1982 with less than half the number of wells drilled.

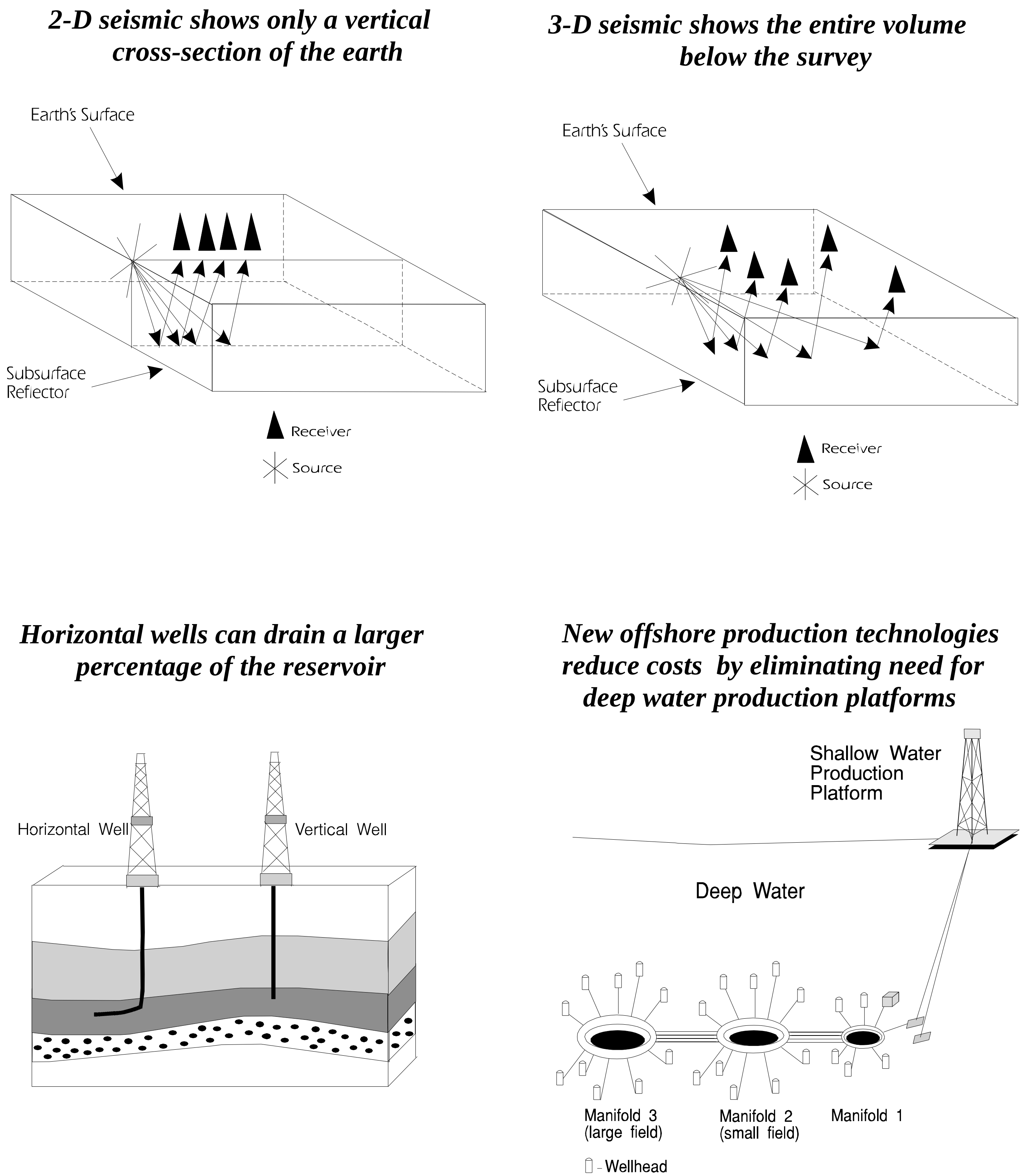
- **Annual natural gas production rose 3 percent in 1993 to 18.3 trillion cubic feet, a continuation of the upward trend seen since 1986** (Figure 1). Open access to pipeline transportation has resulted in more marketing opportunities for producers and greater competition, leading to increased production. New knowledge of gas reservoirs has led some States to revise their well-spacing rules, allowing producers to increase production via the drilling of infill wells.[2] As a result, production has increased from fields once considered too mature to produce at high levels. Production from the top 100 gas fields, most of which are over 50 years old, was 32 percent higher in 1991 than in 1982. For example, the Hugoton field, discovered in 1922, has produced more gas than any other U.S. field. It produced 516 Bcf in 1991 compared with 328 Bcf in 1982. Additional production increases are expected during the next few years because of changes in State prorationing rules in 1993.

- **Increased production has tended to be concentrated in the traditionally off-peak summer months.** Summer production has been largely dedicated to the injection of gas into storage for later winter use and for incremental demand from electric utilities and industrial cogenerators. Consequently, production now exhibits less month-to-month variation, providing for more efficient use of existing capacity.

- **Productive capacity is projected to remain adequate to support increases in production** (Figure 1). Preliminary results of an Energy Information Administration analysis of wellhead productive capacity indicate that (under the base case assumptions) productive capacity will rise in 1995 in response to projected drilling increases.[3] By December 1995, productive capacity is projected to reach 61.6 Bcf per day, slightly higher than the 60.9 Bcf per day estimated for December 1992.

The gas supply industry in 1985 was saddled with overcapacity and high costs. Today the industry is more efficient and produces more gas at a lower wellhead price. However, the ability of the industry to sustain production at prices competitive with low-priced alternatives depends on the ability of producers to apply new extraction technologies, as well as the size and characteristics of the accessible resource base.

Figure 2. Technological Advances Enhance Supply



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

Natural Gas Supply: Technological Advances

Technological advances have enhanced the industry's ability to find and develop new gas reserves at competitive prices. According to the National Petroleum Council (NPC), advances in drilling have lowered real drilling costs by 3 percent per year during the past 20 years.[4] Some of the most significant improvements in technology have come in the realms of seismic surveying, drilling, and well completion techniques. The NPC estimates that technology advances will add more than 230 trillion cubic feet (Tcf) to the resource base by 2010.

- **The adoption of three-dimensional (3-D) seismic surveys during the 1980's has lowered the risk of drilling a dry hole.** During a seismic survey, seismic waves generated at the earth's surface pass through the earth and are reflected back to the surface and recorded. The recorded reflections are processed and analyzed for indications of gas- and oil-bearing strata. A conventional two-dimensional (2-D) seismic survey collects data along a survey line on the earth's surface. This gives a 2-D vertical cross-section of the geology below the survey line, but provides little information about the geology on either side of the cross-section (Figure 2). A 3-D seismic survey collects data over a survey area and provides a 3-D image of the geology below the earth's surface. Because of the enormous amount of data collected with a 3-D survey, this technology only became viable with the rapid advances in computer processing power experienced during the 1980's.[5]

  Three-dimensional seismic surveys have helped boost production from existing fields in the Gulf of Mexico. For example, Mobil Exploration and Production U.S. Inc. has increased gas production from its 21-year-old East Cameron Block 286 field off the Louisiana coast. Gas was targeted below the currently producing field based on the results of a new 3-D seismic survey. Gas production from the East Cameron field is currently reported at 100 million cubic feet (MMcf) per day. Just 3 years ago the East Cameron field produced 25 MMcf per day.

- **The use of polycrystalline diamond compact (PDC) drill bits has shortened drilling times and lowered drilling costs.** Drilling technology advances are particularly important for accessing large volumes of deep gas deposits believed to occur below 15,000 feet.[6] The development of this gas has previously been constrained by low prices and the high cost of drilling.

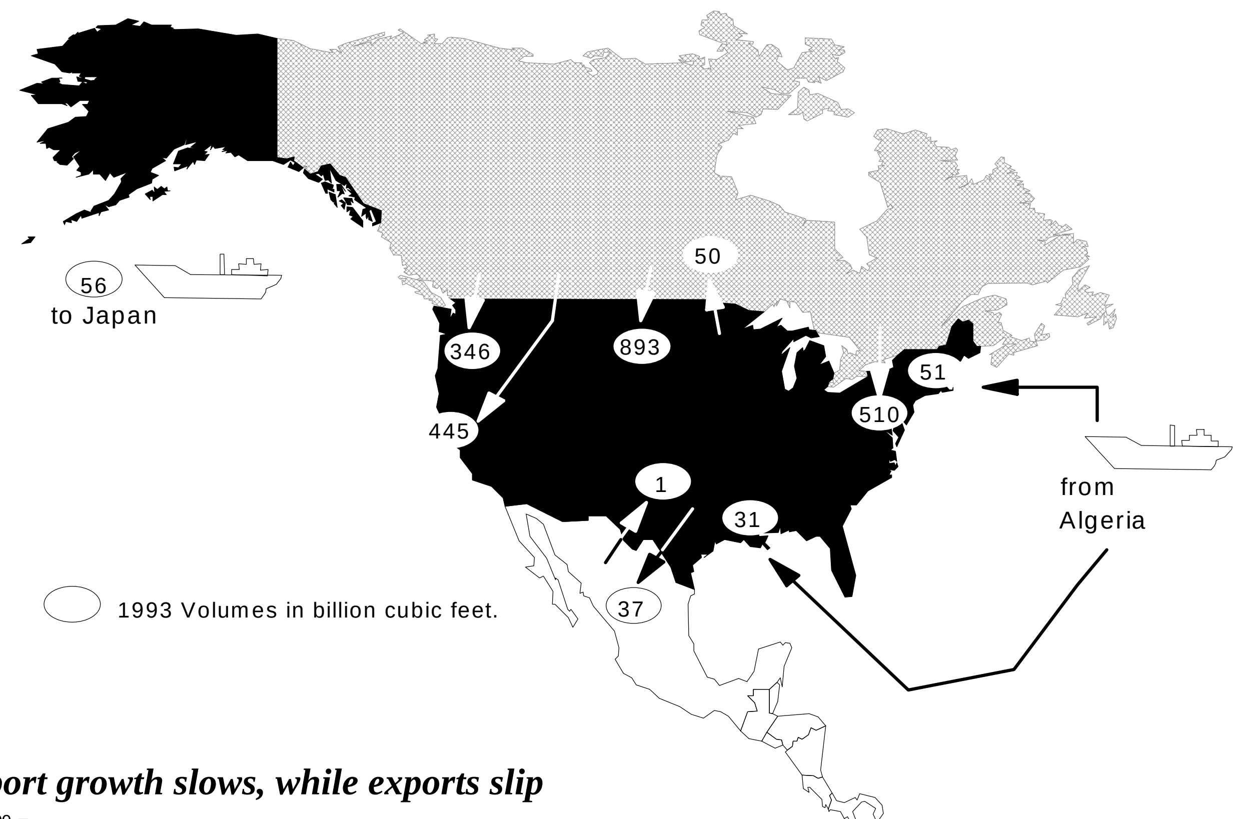
- **New gas supplies will become available from the increased application of horizontal drilling in natural gas fields.** Most gas reservoirs are much more extensive in their horizontal (areal) dimension than in their vertical (thickness) dimension. For instance, a typical reservoir might be only 20 feet thick but cover many thousands of square feet. A conventional vertical well can drain only a small percentage of a reservoir compared with a horizontal well (Figure 2). Most horizontal wells drilled to date have targeted oil reservoirs. As the technique improves and becomes cheaper to employ, horizontal drilling should become more widely used in the gas industry.[7]

- **Advanced fracturing techniques have had some striking successes in increasing gas flow from tight sand reservoirs.** The use of new chemicals in the fracturing process allows sand-laden fluids to drain away, leaving the sand behind as a prop to hold open the fractures.[8] Fracturing should improve the economics of drilling for gas in tight formations. Gas from tight formations represents 27 percent of the estimated total lower 48 gas resource base of approximately 1,300 Tcf.[9]

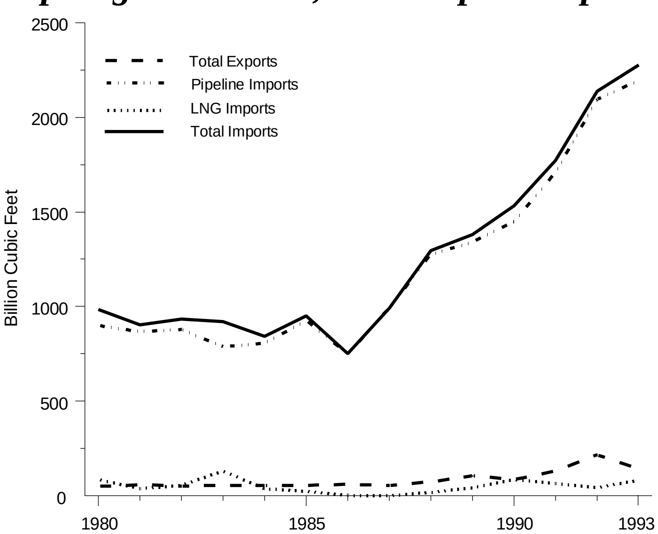
- **Advances in offshore platform design, subsea well completion techniques, and associated underwater technologies now allow offshore gas prospects to be developed at greater water depths than before.**[10] New offshore technologies are being used in the deep waters of the Gulf of Mexico, where many larger gas prospects should be found. Subsea completions and underwater production manifolds will enable production from new deep water prospects at a lower cost than originally estimated. Using these underwater technologies, deep water prospects will be developed at a fraction of the cost of permanently placing a surface production platform in deep waters. The oil and gas produced using this technology can be piped to a shallow water host platform, a cheaper alternative (Figure 2). Costs can be further reduced by using an existing shallow water platform, situated above an older declining field.

While the domestic industry currently provides about 90 percent of domestic consumption, a significant and growing contribution is being made by imports of natural gas.

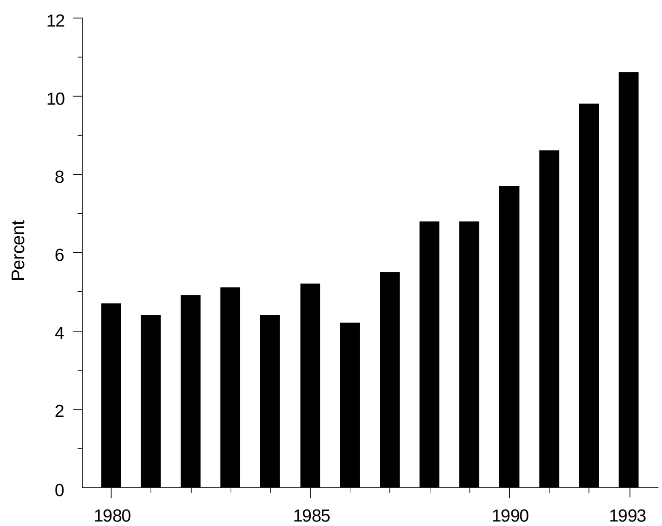
Figure 3. North American Gas Trade Continues to Expand but at a Slower Pace



Import growth slows, while exports slip



Net imports represent a steadily growing proportion of total gas consumed



LNG = Liquefied natural gas.

Note: Regional data for imports from Canada on the map were derived by applying regional shares based on import data from the Department of Energy, Office of Fossil Energy, to total Canadian imports from the Energy Information Administration.

Sources: Energy Information Administration. **1980-1992:** *Natural Gas Monthly*, August 1993. **1993:** Canadian imports in map—Office of Oil and Gas, derived from *Natural Gas Monthly*, April 1994 and Office of Fossil Energy source data for *Natural Gas Imports and Exports, Fourth Quarter Report 1993*; Algerian imports in map—Office of Oil and Gas, source data for *Natural Gas Monthly*, April 1994; Others—*Natural Gas Monthly*, April 1994.

Natural Gas Supply: Imports and Exports

Pipeline imports continued to grow in 1993 but at a slower rate than the record-setting pace in 1992, while pipeline export levels dropped substantially from their record highs of 1992. Only imports of liquefied natural gas (LNG) from Algeria, which nearly doubled from 1992 levels, increased substantially, whereas exports of LNG to Japan stayed relatively flat. In an unexpected development, in December, Mexico began exporting natural gas to the United States for the first time since 1984.

- **The largest component of U.S. import and export trade in natural gas continues to be pipeline imports from Canada, representing 11 percent of U.S. gas consumption in 1993.** After increasing by 22 percent from 1991 levels to a record high of 2,094 billion cubic feet (Bcf) in 1992, Canadian gas imports continued to grow, but by a modest 5 percent, to 2,194 Bcf in 1993 (Figure 3). Pipeline exports to Canada, after reaching a 20-year high of 68 Bcf in 1992, dropped by 26 percent to 50 Bcf in 1993.

- **Import growth into California remained steady, despite a controversy with Canadian producers that dampened short-term imports for the first 10 months of 1993.**[11] A decision by California regulators to allow capacity release caused the Canadian National Energy Board (NEB) to prohibit (effective late-June 1992) short-term exports through Kingsgate and Huntingdon, British Columbia, except under contracts with Alberta and Southern Gas.[12] Consequently, short-term imports destined for California for the first 10 months of 1993 (30.1 Bcf) were 44 percent lower than for the same period in 1992 (53.3 Bcf). After more than a year of negotiations, the affected U.S. and Canadian companies agreed to restructure their sales contracts. Accordingly, the NEB revoked its orders on this matter effective November 1—and short-term imports in November and December skyrocketed to seven times the volume imported in those months in 1992.

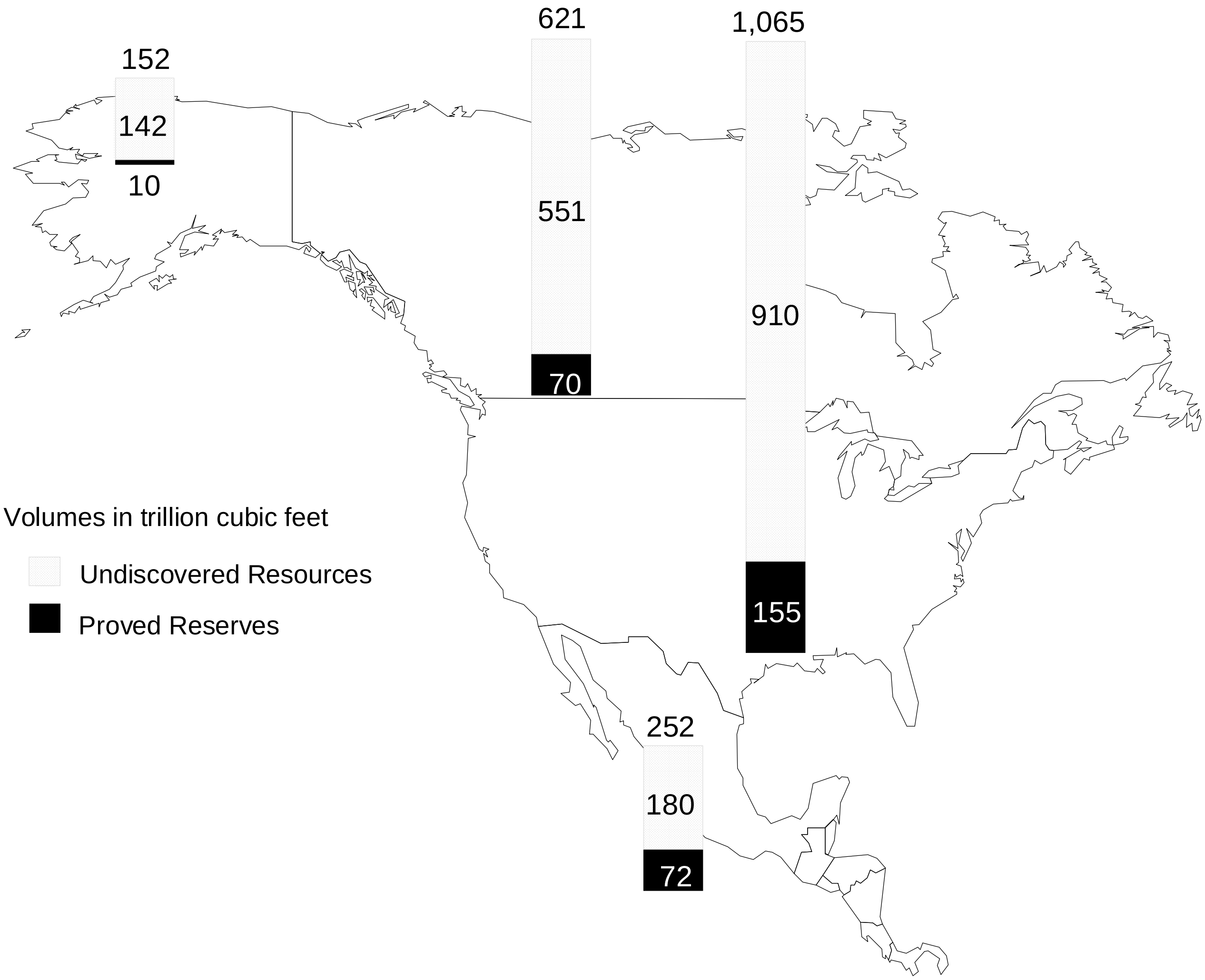
- **Import capacity from Canada increased by 1.8 Bcf per day during 1993 with completion of several major projects**, including a 0.9-Bcf-per-day expansion by Pacific Gas Transmission into California. Numerous other projects have been planned, which, if completed as originally proposed, could expand import capacity to 10.5 Bcf per day by 1996, or nearly 42 percent from the 1992 level of 7.4 Bcf per day. However, it is possible that some of these projects will be delayed or canceled, particularly in light of the extensive capacity already available into California and other major markets.

- **While Mexico has been expected to develop as a significant market for U.S. natural gas in the near term, higher prices, coupled with Mexico's slumping economy, contributed to sharply curtailed demand in 1993**. Pipeline exports to Mexico, after increasing to 96.0 Bcf in 1992—nearly 60 percent above the record level of 60.4 Bcf set in 1991—plummeted to 36.8 Bcf in 1993. Mexico's economic downturn, coupled with small amounts of new associated gas production from oil fields coming on line in southern Mexico, has produced a mini-glut of gas. In 1993, Petroleos Mexicanos (PEMEX), the Mexican energy agency, began exporting natural gas to the United States for the first time in 9 years, albeit at modest levels (just under 1 Bcf in December). At least three projects to increase cross-border capacity with Mexico have been proposed, which, if completed, would expand capacity by 583 million cubic feet per day. The 1993 export results may affect the size, pace of progress, or even the feasibility of these projects.

- **The extensive import and export trade in 1993 reflects the trend toward development of an increasingly integrated North American gas industry.** Canada's large resource base and competitively priced gas supplies provide U.S. marketers and consumers, particularly on the West Coast and in the northern States, with increased supply options. The development of a still broader gas industry that incorporates significant gas trade with Mexico is some years away. It will depend on a number of interrelated developments in Mexico's economy in general and its oil and gas industry in particular—notably, paying off international debt, developing the oil and gas resource base, and building additional production and transmission infrastructure. The North American Free Trade Agreement (NAFTA) will help foster the development and integration of the Mexican gas industry.

North America has significant natural gas resources. The continuing development of a North American market for natural gas holds substantial potential for the domestic market.

Figure 4. North America Has Vast Natural Gas Resources



Note: Resource base estimates include resources in areas currently off limits to exploration and development. Resource and Mexican reserve data are estimates as of December 31, 1990, using current technology. Other proved reserve data are estimates as of December 31, 1992, using current technology.

Sources: **Resources and Mexican Proved Reserves:** National Petroleum Council, *The Potential for Natural Gas in the United States: Source and Supply*, Vol. II, December 1992. **U.S. Proved Reserves:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1992 Annual Report*. **Canadian Proved Reserves:** Canadian Petroleum Association, March 1994.

Natural Gas Supply: Prospects for the Future

North America has a vast natural gas resource base to support growing natural gas demand (Figure 4). Into the 21st century, natural gas supplies will be determined within this increasingly integrated market.

- **The supply of natural gas is sustainable over the long term.** The technically recoverable resource base is the level of proved reserves (gas that can be readily produced) plus the amount of gas that can be found and developed under current prices and technology. At the end of 1992, proved reserves in the United States (including Alaska) equaled 165 trillion cubic feet (Tcf), equivalent to roughly 10 years of production at current rates. In its 1992 study, *The Potential for Natural Gas in the United States: Source and Supply*, the National Petroleum Council estimated a technically recoverable gas resource base for the lower 48 States of 1,065 Tcf, sufficient gas to meet U.S. demand at current levels for about 60 years.[13] Alaska has an additional 152 Tcf in potential supplies, while Canada's gas resource base is estimated at 621 Tcf. In addition, Mexico's gas resource base is estimated at 252 Tcf. The opening of the Mexican oil and gas industry to foreign investment will facilitate technology transfers, which will promote development of the Mexican gas resource base. Improved access to all these resources provides grounds for optimism about the role of natural gas in the Nation's energy future.

- **Gas supplies to the lower 48 States could become available from the Canadian frontier and Alaska, but are not expected prior to 2010.**[14] The industry has a strong incentive to develop the significant gas resources in inaccessible regions of Canada and Alaska. However, gas pipelines from these regions are not feasible given current prices. Breakthroughs in the liquefaction of gas or electricity wheeling (so that electric plants could be established near remote gas fields) are two possibilities being researched to exploit this gas.

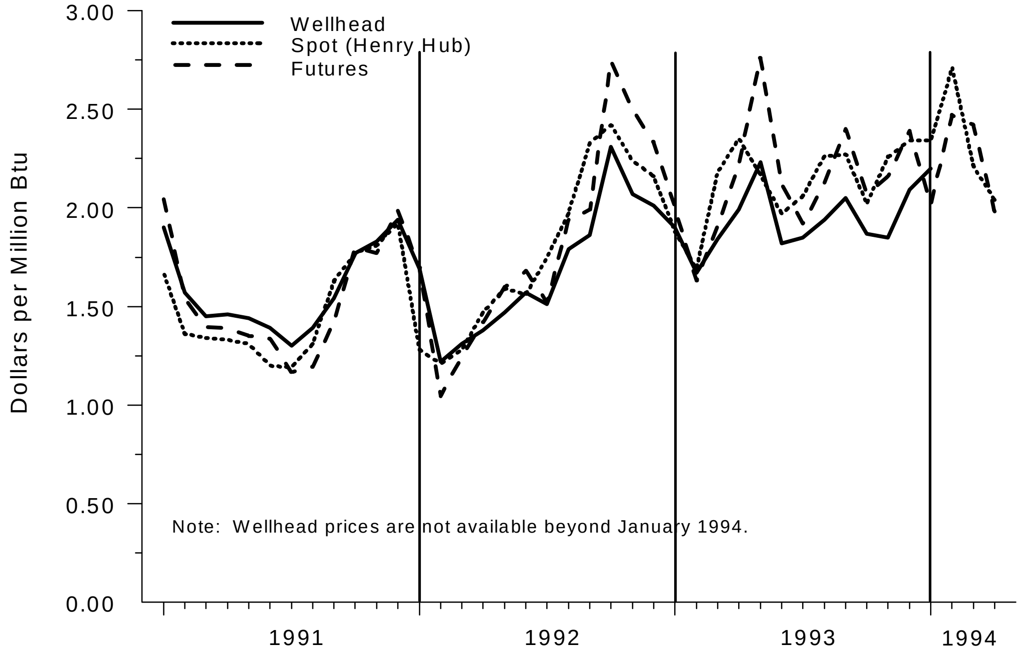
- **New technology is expected to increase the resource base.** Under the expected technology of 2010, the technically recoverable resource base is estimated to equal 1,295 Tcf, more than 200 Tcf higher than under current technology. An example of the role that new technology can play in accessing more of the resource base is provided by the recent use of "super computers" in conjunction with 3-D seismic surveys. Using this technology it is possible to produce images of previously undetectable gas and oil-bearing geologic structures beneath salt layers under the Gulf of Mexico. In October 1993, a consortium led by Phillips Petroleum reported the first commercial subsalt discovery 80 miles off the coast of Louisiana. Test flows of almost 10 million cubic feet per day of natural gas (and 7,000 barrels per day of oil) were reported from the discovery well.[15] The industry is very optimistic about the potential for future subsalt discoveries. At a recent lease sale, over $227 million was bid for offshore leases, many of them overlying subsalt prospects.

- **Current technically recoverable resource estimates may understate the long-term supply of natural gas**. While over 3 million wells have been drilled in the United States since 1959, only a few thousand have depths greater than 10,000 feet. Below this depth, the United States remains largely a frontier region. The U.S. Geological Survey has speculated that almost 3,200 trillion cubic feet of gas may be present at depths between 14,000 and 22,000 feet. The high cost of drilling a deep well precludes considering these prospects as part of the technically recoverable resource base. However, further technological advances should eventually result in the development of the onshore deep frontier.

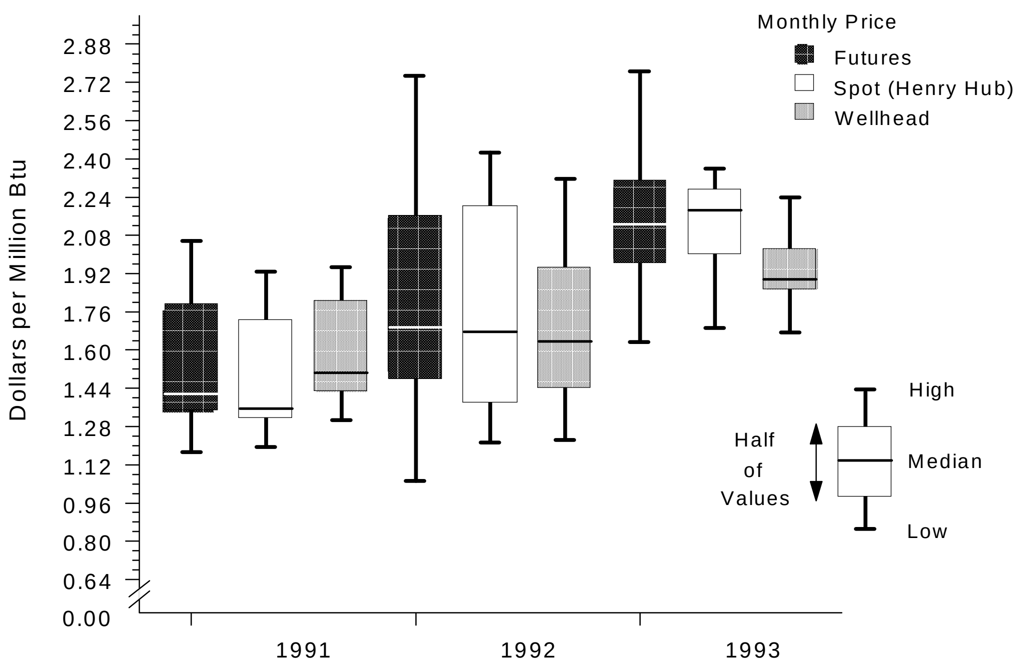
  The U.S. Geological Survey has estimated that tight formations in Wyoming's Greater Green River Basin alone may contain over 5,000 trillion cubic feet (Tcf) of gas. Although not economically recoverable in the immediate future, this gas could play an important role in satisfying demand after more conventional supplies are depleted. Another potentially important source of supply is gas from geopressured aquifers. While the economics are currently marginal, the U.S. Geological Survey has estimated 5,700 Tcf of geopressured gas may occur in deep aquifers. Gas hydrates located in Alaska and off the U.S. coast are another example of a speculative, but potentially important source of gas. It is estimated that these regions could provide between 485 and 3,109 Tcf of gas. However, current technology is inadequate to recover gas from these sources.

Figure 5. Wellhead, Spot, and Futures Prices Were Higher in 1993

Prices continued upward . . .



. . . But were more closely clustered



Sources: **Futures Prices:** Commodity Futures Trading Commission, Division of Economic Analysis. **Spot Prices:** The Oil Daily Company, *Natural Gas Week*. **Wellhead Prices:** Energy Information Administration: 1991—*Natural Gas Monthly*, March 1994, 1992-January 1994—*Natural Gas Monthly*, April 1994.

Changing Market Dynamics: Wellhead, Spot, and Futures Prices

Wellhead prices moved sharply higher in 1993, averaging $1.99 per thousand cubic feet (Mcf), 14 percent higher than in 1992. This is the highest level reached since 1985, when prices averaged $2.51 per Mcf.

The largest monthly changes in 1993 occurred between April and June as the market recovered from the effects of a late winter storm. From April to May, prices increased $0.25 per Mcf in response to the increased demand for gas by storage operators. Wellhead prices then fell $0.43 per Mcf between May and June when injections of gas into storage were reduced because storage levels were perceived to be adequate. However, overall monthly variability in price throughout the year was generally less in 1993 than in either of the previous 2 years (Figure 5).

Furthermore, the seasonal pattern of price variation that developed in the late 1980's, where prices rose in the winter and declined in the spring and summer, was not evident in the wellhead market in 1993. For example, in 1993, the average wellhead price peaked in May. In contrast, the 1992 peak was in October, more in line with the normal seasonal peaks occurring during the heating seasons. Both the reduction in monthly price variability and in seasonality may be due, in part, to the increased utilization of underground storage throughout the year.

Prices on the futures and spot market at the Henry Hub were similar and tracked closely throughout the year. However, futures prices tended to move sharply higher during periods of stress, exceeding spot prices for the same delivery month.

- **The 3-percent increase in demand for natural gas in 1993 and the reduction of excess gas supplies in early 1992 were the principal factors supporting the higher prices, but storage activity also put upward pressure on prices**. Underground storage injections were higher in 1993 than in 1992 in 7 of the last 9 months of the year. In addition, State prorationing rules were changed in 1993, lowering the authorized level of monthly production in major producing States, and potentially keeping gas off the market. These factors contributed to higher wellhead prices in 1993.

- **The reduced seasonality in prices for 1993 may be, in part, a consequence of the growth of the futures market and of the increasing flexibility of the gas industry.** If prices for future delivery are relatively high, this encourages the industry to place more gas in storage today for future delivery. When the stored gas is released onto the market, it tends to lower the price. The much more active storage industry means that it is no longer necessary for producers to bring on line as many inefficient wells as it had in the past to satisfy incremental gas demand during the peak winter season. Instead, the industry is relying more on storage withdrawals for incremental supplies during the peak season, which alleviates upward pressure on prices at the wellhead.

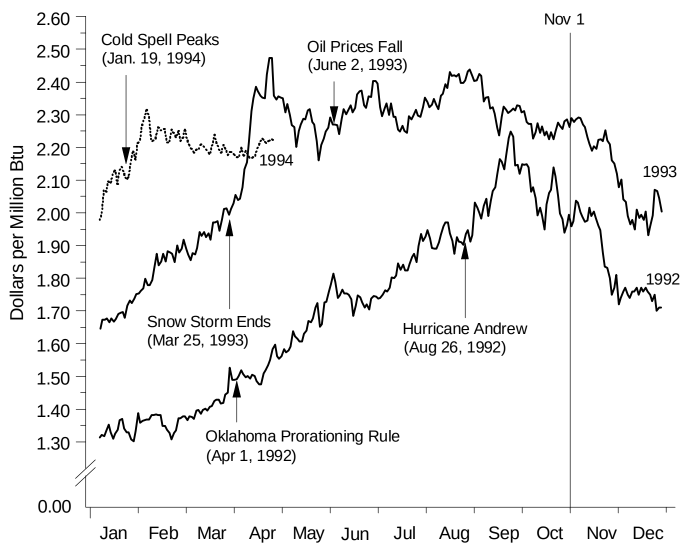
- **Increased use of storage throughout the year has also moderated the monthly changes in gas prices.** In 1993, the range of wellhead prices over the year varied by $0.58 per thousand cubic feet (Mcf), about half of the $1.12 per Mcf range in 1992 and 12 percent less than the range in 1991. During 1993, wellhead prices were more closely clustered for much of the year, with a $0.18 per Mcf interquartile range (i.e., the range of half of the observations shown by the boxes in Figure 5). In contrast, the range was $0.40 per Mcf in 1991 and $0.53 per Mcf in 1992.

- **Futures prices tended to exceed both spot and wellhead prices in 1993, especially during periods of stress.** The futures market at the Henry Hub for a delivery month closes before all deals for the shipments of gas from hubs, production sites, or other transfer points for gas supplies in the United States are completed. The futures price, however, is frequently used as an initial reference price in negotiating many of these deals. High futures prices frequently result from perceptions that storage levels are too low to meet gas demand. As the market adjusts after the close of the futures market, and it becomes clear that supplies are adequate, the prices drop. This was the case in May 1993 when the futures settlement price for May delivery was $2.76 per million Btu (MMBtu) while the average spot price at the Henry Hub for the same delivery month was $2.17 per MMBtu.[16]

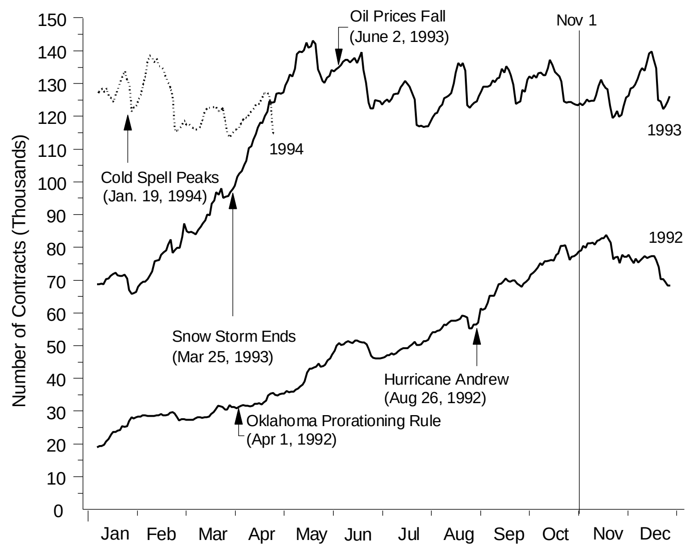
The futures market has become an integral part of pricing decisions being made in the natural gas market on a daily basis. It has shown substantial and continuing growth since its inception in 1990 and has become the financial benchmark of many contractual arrangements.

Figure 6. The Use of Natural Gas Futures Grows Dramatically

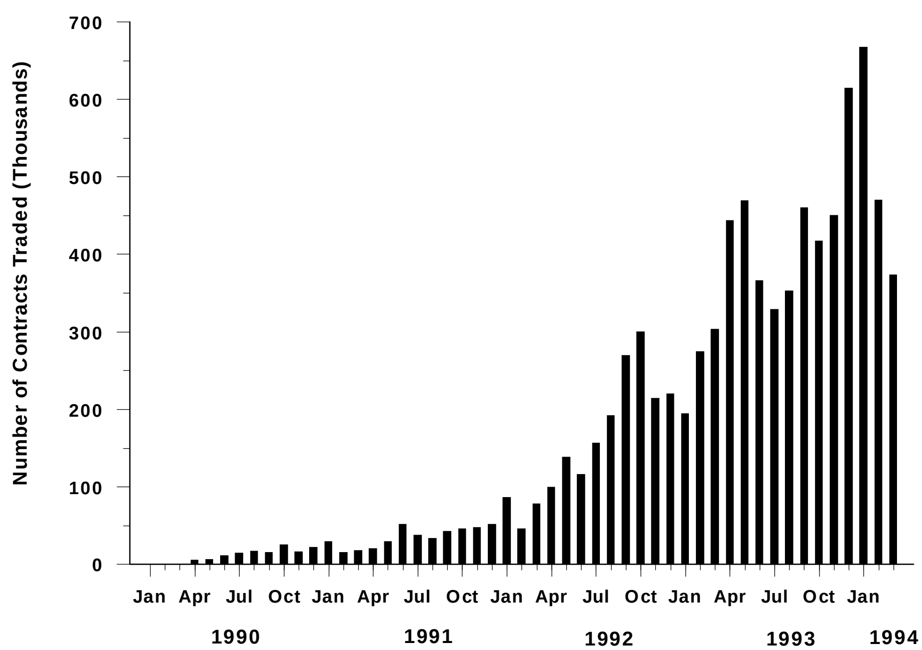
Futures prices rose sharply in spring 1993 . . .



. . . Leading to more futures contracts



. . . While increased trading shows market liquidity



Note: Aggregate open interest (number of outstanding contracts) typically declines around November 1 because the relatively high-volume contracts for December, January, and February are expiring.

Sources: Commodity Futures Trading Commission, Division of Economic Analysis.

Changing Market Dynamics: The Futures Market

Significant price uncertainty in the natural gas market fueled dramatic growth in the use of the futures market during 1993. At the beginning of 1993, the number of gas futures contracts (open interest) exceeded heating oil futures contracts for the first time. Natural gas open interest reached 143,165 contracts on May 19, the highest level for the year.[17] This level was double the number of contracts at the beginning of the year and exceeded heating oil open interest by almost 40,000 contracts.

Prices on the futures market moved sharply higher in the early months of 1993, but moderated in the later months as oil prices declined and concern about adequate storage levels for the heating season abated. Daily variability in the price of gas on futures and cash (spot) markets continued to be significant and contributed to the 83-percent increase in open interest from the beginning to the end of the year. The large rise in the futures price of gas (Figure 6) in the spring of 1993 was accompanied by strong growth in the number of contracts. An even greater increase in monthly trading volumes was seen during the year. At the end of 1993, the average monthly volume of trade was more than three times greater than its level at the beginning of 1993.

- **The expected continuation of rising demand for natural gas and a closer supply and demand balance contributed to the higher level of futures prices in 1993.** Demand for natural gas increased in 1993 and is expected to increase during the next several years. On the supply side, wellhead productive capacity was reduced (by about 4 percent) in 1992 in response to very low prices at the beginning of the year and continued to decline slightly (by less than 2 percent) in 1993. Both of these factors supported higher prices.

- **Market growth also occurred because contracts now trade for 18 future delivery months.** The extension of the futures contract market from 12 to 18 months occurred during January 1992. As the industry became increasingly familiar with the longer term futures contracts, trading in these contracts grew. The extension for an additional 6 months allows market participants to support longer term contracts for the physical commodity, since price risk can be managed through the futures contracts for an additional 6 months.

- **The exchange of futures for physicals (EFP's) is increasingly used by the gas industry to arrange deals.** EFP's require buyers and sellers of natural gas first to take positions in the futures market before completing a deal in the physical market. Exchanges arranged through an EFP increased from about 45 billion cubic feet (Bcf) in January 1993 to about 130 Bcf in January 1994. The popularity of EFP's is supported by the value of the futures market as a means of price discovery and the flexibility of these instruments.

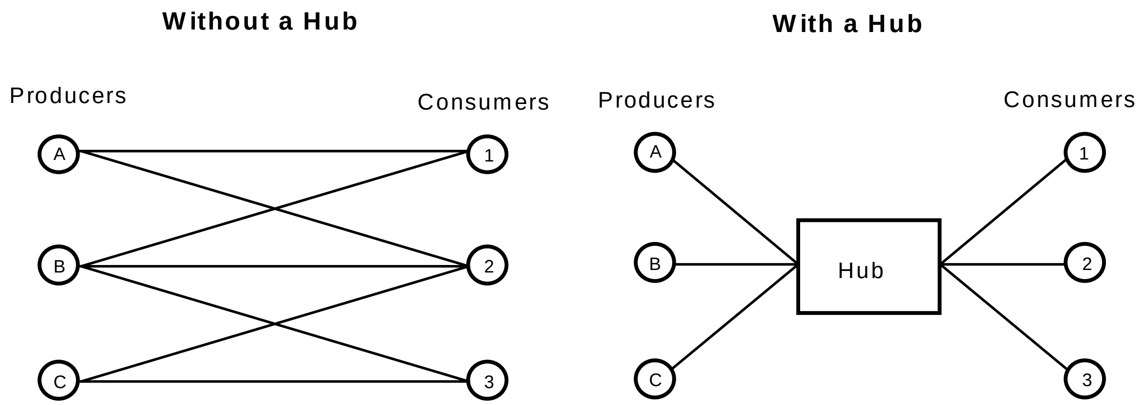
- **New financial instruments continue to be developed, and the nonregulated portion of the financial market continues to grow.** As the need for risk management services increases under the restructured industry and as the futures contract market continues to grow, new price hedging instruments continue to be developed. For example, price insurance is available whereby the insurance buyer pays a certain percentage of the current cost of gas as a premium.[18] In return the buyer of the insurance is reimbursed if the price of gas rises above some set value. The growth of the futures market also supports the development of the options market and of the nonregulated markets in swaps and options.[19] The futures contract market price is used directly by the nonregulated market when offering these financial instruments. Futures contracts are used, at times, by the financial industry to hedge its own risks in arranging swaps contracts through which buyers and sellers can fix prices.

- **The liquidity of the market has increased.** The continued growth and importance of the futures market is supported by the liquidity of the market, where buyers and sellers are readily able to complete exchanges near expected prices. If a market lacks liquidity, willing sellers outnumber willing buyers (or vice versa) and the volume of completed trades declines. The growth in the volume of trades in the gas futures market gives every indication it is a very liquid market (Figure 6).

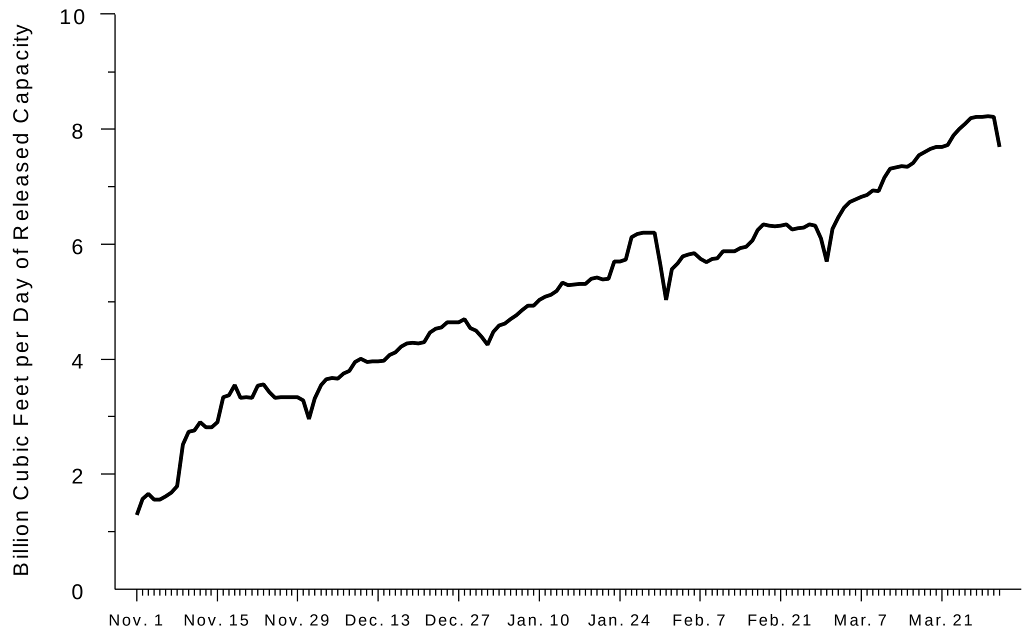
The futures and related financial markets are important components of the market today and are essential support for the increasing market flexibility that has been developing under open access regulation. With the implementation of Order 636, substantial additional flexibility has been introduced into the market.

Figure 7. Changing Market Dynamics

Market hubs provide more direct access to a wide variety of supplies and markets



Use of released capacity increased during the first heating season under Order 636



Note: Capacity release data have not been adjusted for recalled or re-released capacity.
Sources: **Market Hub Diagram:** Energy Information Administration, Office of Oil and Gas. **Released Capacity:** Pasha Publications Inc.

Changing Market Dynamics: Increased Flexibility

Increased flexibility in buying and selling gas was an important development for the industry in 1993. This flexibility was achieved through the development of additional market hubs, creation of a secondary market for capacity rights, introduction of new services, and implementation of more flexible receipt and delivery points. All of these factors have contributed to a more dynamic, customer-focused market for gas services.

- **New market hubs developed in 1993 and more were proposed.** New market hubs were created in Chicago, in Ellisburg-Leidy (Pennsylvania), and in New York, bringing the total number of hubs to over 20. In addition, companies representing all segments of the natural gas industry plan to create hubs in the near future. Market hubs are geographically dispersed throughout the United States, mainly near supply basins, storage sites, and downstream pipeline interconnections. Hubs provide both physical and transactional services. Physical services include gas wheeling,[20] parking,[21] transportation, storage, compression, and processing. Transactional services being offered consist of title transfer, buyer-seller matching, balancing, and electronic bulletin board (EBB) information. These services support economic or informational functions without relying on physical facilities. Market hubs are an integral part of restructuring gas services because they (1) promote greater competition by bringing more buyers and sellers together; (2) improve the efficiency of the pipeline network by linking supply, storage, pipeline interconnect, and distribution areas more completely (Figure 7); and (3) improve reliability by giving end users access to more supply options than they had in the past.

- **Implementation of capacity release programs during 1993 presented end users with additional flexibility in reselling unneeded transportation capacity rights.** Although releases occurred earlier in the year, full-scale implementation of capacity release programs by pipeline companies was not required until November 1, 1993. While trading activity on the secondary market began slowly, it built up steadily during the heating season (Figure 7). As expected, weekly variations in the availability of capacity were affected by fluctuations in weather. During the severe cold spell in the third week of January 1994, capacity available for release declined significantly and some capacity was recalled. By late March 1994, nearly 15 percent (8.2 billion cubic feet) of U.S. total winter peak capacity was held by replacement shippers.[22] The secondary market gives more flexibility to holders of capacity rights in that a market now exists for them to resell or "lease" capacity they do not need to other shippers. This makes it more attractive to enter into long-term capacity contracts. Prices for released capacity have ranged from $0.01 per million Btu to the maximum reservation fee. Discounts on releases have been common.

- **An array of new services was offered last year to help end users take advantage of the restructured industry.** A broad mix of new transportation, storage, balancing, risk management, supply, and rebundling services is now available (see Chapter 2). End users are now able to pick and choose only the services they need from an expanded menu of options. The new service selections make it easier for end users to make tradeoffs between the quality of service they want and the price they are willing to pay.

- **Flexible receipt and delivery points.** Pipeline customers with firm capacity rights now have more flexibility in changing where they choose to inject or withdraw gas along pipeline trunklines. These changes were instituted to promote the secondary market for capacity. Firm capacity rights are more valuable now because purchasers of released capacity may specify, at no extra cost, different receipt and delivery points than those belonging to the releasing shipper, as long as the gas moves along the same transportation path within the same zone.

Changing market dynamics have altered the opportunities and risks facing industry participants. While deregulation has increased market exposure and reallocated risk, it has also fostered competition and the introduction of new services. These trends have compelled participants to consider alternative strategies to manage these risks and to take advantage of new market conditions.

Table 1. Competition and New Opportunities Also Carry Risks

Industry Segment	Opportunities	Risks
Producers	• Improved access to storage and transportation facilities • More direct competition at the wellhead, as changes in transportation rate design eliminate transportation rate distortions of earlier rate designs on wellhead prices • Use of hubs to expand markets	• Changes in the Federal Energy Regulatory Commission's (FERC's) approach toward regulating gathering services may affect gathering rates—if rates increase, producer revenues may decline • Increased competition from other suppliers, as well as low competing fuel prices (e.g., low-sulfur residual oil), puts downward pressure on wellhead prices
Marketers	• Improved access to storage and transportation facilities • Use of hubs to reach more customers and provide new services • Rebundling services to end users that prefer "one-stop" shopping • Use of electronic bulletin boards to facilitate the buying and selling of capacity	• Improved access to facilities is resulting in intense competition from other marketers (including producer and pipeline company affiliates) to develop and promote customer services • Uncertainty under Order 636 about ability to continue third-party contracting separate from pipeline capacity release programs may limit their flexibility in providing services to some customers
Interstate Pipeline Companies	• Guaranteed short-term recovery of most fixed costs • Transferred risk associated with the merchant function to local distribution companies and end users • Increased flexibility on the grid allows pipeline companies to increase utilization of their systems • Creation of new services (regulated and unregulated) to meet the needs of diverse customers	• Competition on the pipeline grid may result in substantially discounted transportation rates and the possibility of reduced profitability (or excess capacity for those unable to retain competitive rates) • Costs submitted by companies as "transition costs" have to undergo regulatory review. Some of these costs may not be approved as "transition costs" by FERC and could be disallowed • Availability of discounted firm capacity in the capacity release market may reduce their ability to recover the fixed costs allocated to interruptible service
Local Distribution Companies (LDC's)	• Greater ability to control costs (and select services) as a result of unbundling • Improved reliability from access to more supply areas • Lower interruptible transportation rates may help LDC's retain their customers that have fuel-switching capability • Creation of new services to meet the needs of diverse customers	• Increased supply risk associated with the transfer of the supply aggregation responsibility from the pipeline companies • Continued threat of customer bypass of LDC's, which may reduce the ability of LDC's to recover fixed costs fully • New contracting practices developing since open access may result in increased State regulatory scrutiny

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

Changing Market Dynamics: Risk and Risk Management

There are substantial opportunities associated with the significant regulatory changes that have occurred during the past decade. At the same time, as competition in the natural gas industry has expanded, market-based risks have begun to have a more direct impact (Table 1) and have resulted in the recent emphasis on risk management in the natural gas industry. Risk has always existed in the natural gas industry. It is an inherent element of any industry whether regulated or market-based and a critical factor in any decision-making. But, most important, risk is a constructive component of the industry that disciplines the market and requires industry players to operate efficiently.

Until the late 1970's, comprehensive regulation insulated the natural gas industry from certain types of risk, particularly price volatility. Since the passage of the Natural Gas Policy Act of 1978, Congress and the Federal Energy Regulatory Commission have reshaped the natural gas industry, making it more competitive and market-driven. Light-handed regulation, together with the forces of supply and demand, have reallocated some risks among industry players. To put these issues in perspective, a description of some of the types of risk affecting the natural gas industry are described below. However, it should be noted that many of these risks are common to any competitive market.

- **Regulatory risk**—The risk associated with changes in the policies of local, State, and Federal lawmakers and regulatory agencies

- **Market risk**—The risk associated with the competitive forces within each industry segment, as well as competition from other energy sources

- **Supply risk**—The risk associated with events that cause disruption in production at the wellhead, such as wellhead freezeups or nonperformance by the supplier.

- **Price risk**—The risk associated with fluctuation in the commodity price, as well as prices for gas storage and transportation services

- **Capacity risk**—The risk associated with unavailable pipeline capacity, either because of *force majeure* events or inadequate contracting practices

- **Credit risk**—The risk associated with the financing of company operations, based on perceptions of financial outlook.

There are many benefits of competition and numerous mechanisms available for managing risk. Among the benefits of competition are:

- Increased interaction among buyers and sellers of gas, allowing each greater freedom to seek out the most favorable price and other contract terms

- Increased freedom for buyers to obtain transportation services independently and at locations that best suit their needs

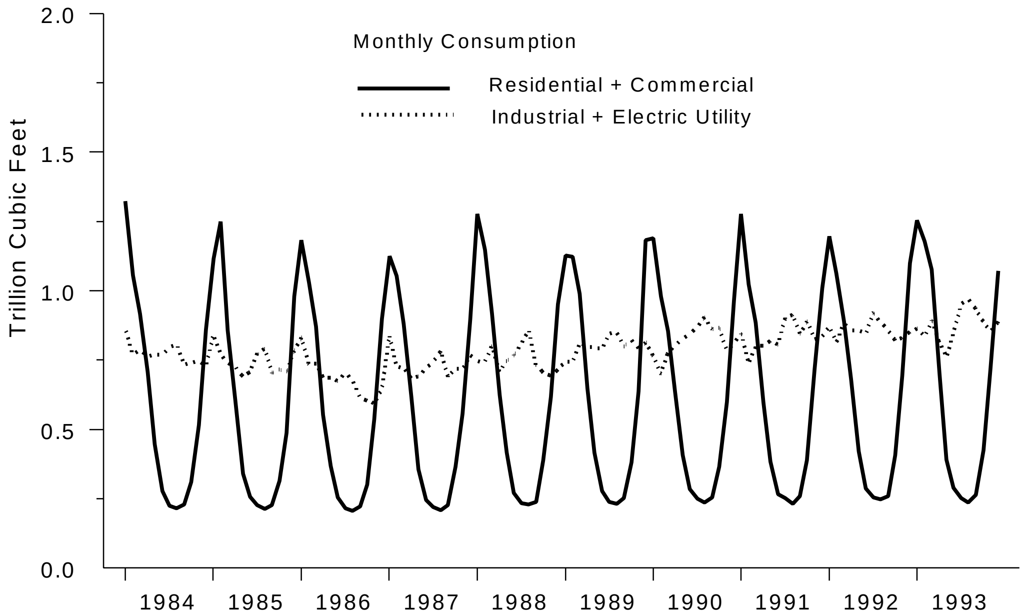
- Availability of a wide variety of gas supply and delivery services and the flexibility to purchase only those services necessary to secure the delivery of purchased supplies

- Potentially increased market efficiency, as buyers and sellers manage their costs of doing business directly and make greater use of the pipeline grid.

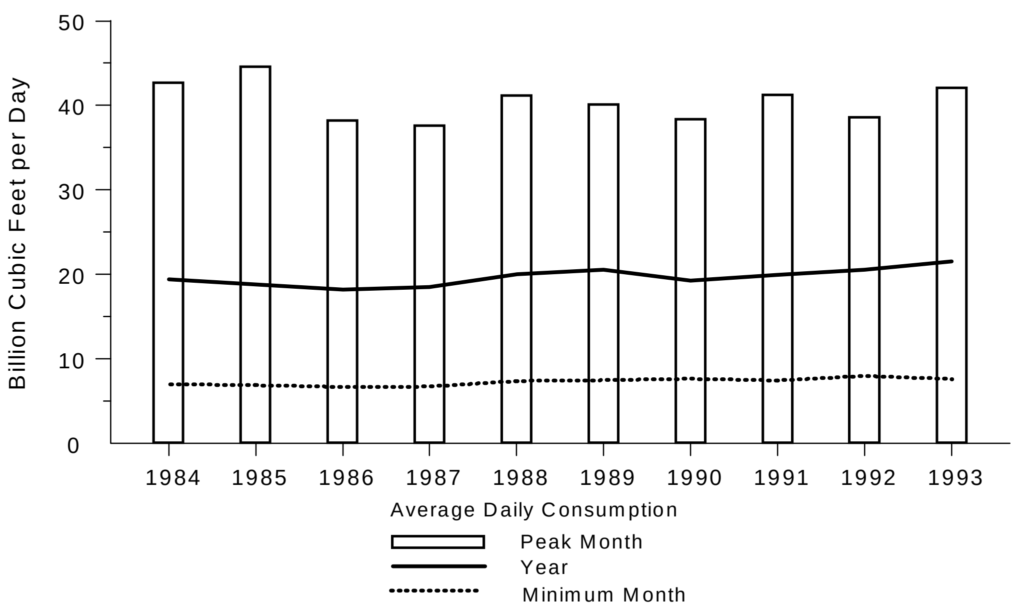
Mechanisms for managing risk have become widely available to market participants. For many market players, the challenge now is to evaluate the risks they face and develop an overall strategy to bring these risks within acceptable levels to achieve the most rewards.

Figure 8. Peak Demand Drives Deliverability Requirements

Weather drives peak residential and commercial demand while industrial and utility demand is far less variable



Daily consumption in the residential and commercial sectors is fairly predictable except during the peak months



Sources: Energy Information Administration, Office of Oil and Gas; based on *Natural Gas Monthly*, historical data series.

Deliverability: Peak Demand Drives Requirements

The demand for natural gas varies greatly from day to day, and year to year, because of weather, business activity, and relative prices between natural gas and other fuels. Cold weather causes demand for natural gas to soar in the residential and commercial sectors. These customers have almost no alternatives for fuel and are thus high-priority users whose local distribution companies (LDC's) usually contract for firm service on their behalf. In contrast, the industrial and electric utility sectors generally have the capability to switch to alternative fuels. These customers (or their LDC's) purchase most of their transportation and supplies under a lower priority interruptible service.

When assessing future load requirements, pipeline companies and LDC's face considerable uncertainty arising from the variability of daily consumption patterns. They must maintain enough capacity to meet the peak-day requirements of their firm service customers. Such customers are entitled to their firm contract amount on any given day even though they may not actually take their full entitlement. This necessitates a flexible transportation and delivery system that can respond effectively to changes in market demand and supply conditions. Adequate deliverability involves maintaining sufficient capacity of gas wells, pipeline and distribution systems, and storage facilities to meet peak-day demands.

- **The requirements of the residential and commercial sectors and other firm service customers largely determine the overall system deliverability requirements.** When planning for deliverability needs, pipeline companies and LDC's must take into account the large seasonal swings in residential and commercial demand (Figure 8). For example, during the period from 1984 through 1993, consumption during the peak month was nearly six times higher on average than during the month of minimum consumption.

- **During peak months, there is considerable variation in natural gas consumption.** From 1984 through 1993, average daily consumption during the peak month for the residential and commercial sectors combined ranged from 38 billion cubic feet (Bcf) per day to 45 Bcf per day, a nearly 20-percent variation (Figure 8). In reality, the actual peak-day variability may have been even greater. Peak-day information is not widely available, and these data represent an average day in the peak month.

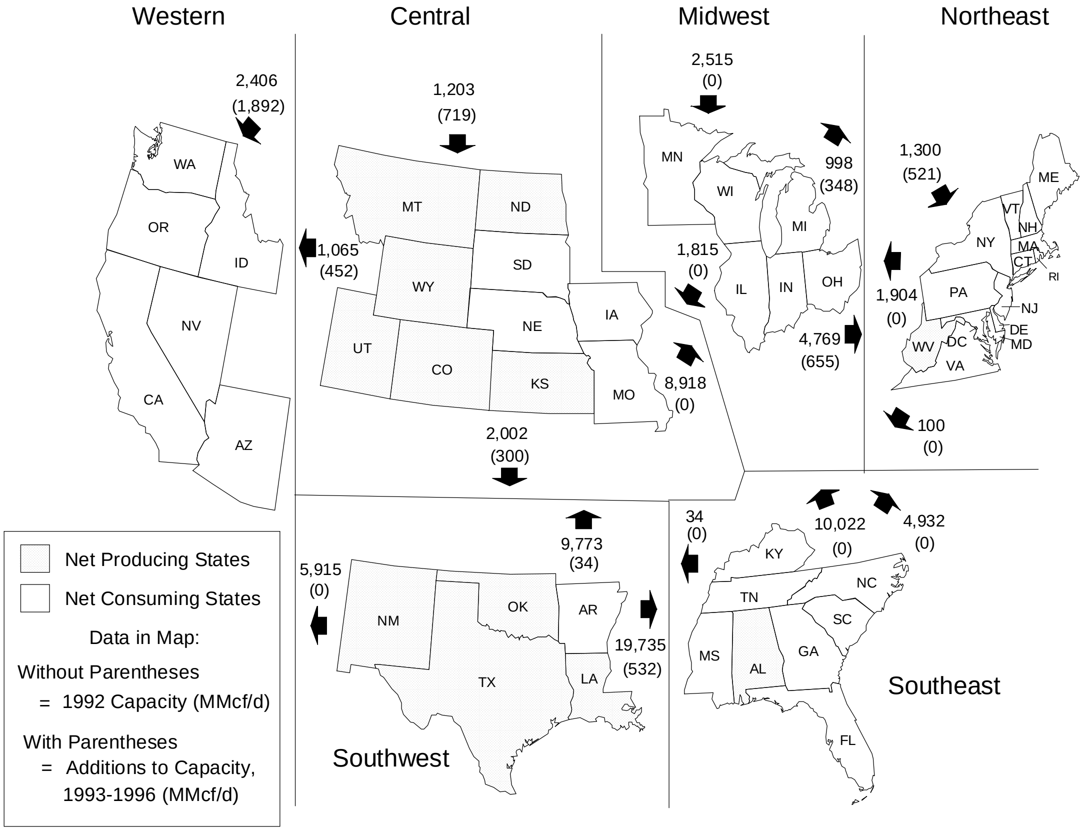
- **Industrial sector consumption shows limited, and diminishing, seasonality.** The variation between the highest and lowest monthly industrial consumption, on an annual basis, has diminished since 1986. The overall increase in industrial consumption of natural gas has been accompanied by an increase in peak monthly consumption. Peak monthly industrial consumption increased from 647 Bcf in 1986 to 726 Bcf in January 1994, an increase of 12 percent. Consumption during the month of least gas use has increased even more, reaching 593 Bcf in May 1993, an increase of 62 percent. The higher industrial consumption during off-peak months may be due to increased gas use by cogenerators to meet space-cooling requirements.

- **Electric utility consumption helps balance the large demand variation in the other sectors.** Peak use of natural gas by electric utilities occurs during the summer when the demand for electricity for space cooling is highest. Gas consumption by electric utilities during the summer far exceeds that in either the residential or commercial sectors.

The delivery requirements placed on the natural gas system during January 1994 illustrate the impact of the seasonal customers. During the third week of January, weather east of the Mississippi River was at least 40 percent colder than normal, leading to record natural gas consumption. Some LDC's reported gas use that was 60 percent higher than what would normally be expected on a winter day. To service this higher load, a number of LDC's and at least 12 interstate pipeline companies met or exceeded record weekly throughput. Eight pipeline companies set all-time records for daily throughput, averaging increases of 8 percent over previous records.[23] The natural gas industry was generally successful in meeting the surge in demand despite some difficulties because of weather-related equipment failure and pressure drops resulting from heavy drawdowns.

With substantial growth expected in the market, expansion of the delivery system, including pipeline transmission and storage capacity, is planned to service the new load and maintain the deliverability and reliability of the system.

Figure 9. Pipeline Capacity Increases in Major Markets



Planned construction projects will increase interregional capacity 7 percent by 1996

Region	Entering the Region[a] (MMcf/d)							Exiting the Region[b] (MMcf/d)						
	Existing Capacity 1992	Scheduled Additions to Capacity[c]					Percent Change from 1992	Existing Capacity 1992	Scheduled Additions to Capacity[c]					Percent Change from 1992
		1993[d]	1994	1995	1996	Total			1993	1994	1995	1996	Total	
Western	9,386	1,333	0	559	452	2,344	25	0	0	0	0	0	0	0
Southwest	2,036	0	300	0	0	300	15	35,423	34	532	0	0	566	2
Central	12,791	34	0	0	719	753	6	11,985	0	300	0	452	752	6
Midwest	23,359	0	0	0	0	0	0	7,582	380	118	405	100	1,003	13
Northeast	11,001	846	55	275	0	1,176	11	2,004	0	0	0	0	0	0
Southeast[e]	19,835	0	532	0	0	532	3	14,988	0	0	0	0	0	0
Total	**78,408**	**2,213**	**887**	**834**	**1,171**	**5,105**	**7**	**71,982**	**414**	**950**	**405**	**552**	**2,321**	**3**

[a]Includes only the sum of capacity levels for the States and Canadian Provinces bounding the respective region.

[b]Does not include export capacity to Mexico.

[c]New capacity has been counted in only one region even though some projects may cross regional boundaries. In the case of a new line, the additional capacity has been included within the region in which it terminates; for an expansion project, it is included in the region where most of the expansion effort is focused.

[d]Capacity additions for 1993 are estimates of actual projects completed.

[e]Several projects planned for the Southeast Region, representing 1,935 MMcf/d in capacity from the Southwest Region, have been indefinitely postponed or canceled.

MMcf/d = Million cubic feet per day.

Sources: **Net Producing and Consuming States:** Energy Information Administration (EIA), *Natural Gas Annual 1992*. **Capacity:** Federal Energy Regulatory Commission (FERC), FERC Format 567, "System Flow Diagrams." **Capacity Additions:** FERC, Natural Gas Act Section 7(c) Filings, "Application for Certificate of Public Convenience and Necessity," and various natural gas industry news sources.

Deliverability: Interstate Pipeline Expansion Continues

The interstate pipeline system continued to expand during 1993, responding to increasing demand and the need for additional operational flexibility under Order 636. Interregional capacity (entering the regions) increased by 2,213 million cubic feet (MMcf) per day during 1993, with another 2,892 MMcf per day planned for completion by the end of 1996 (Figure 9). These additions represent an increase of 7 percent from the 1992 level.

- **Most of the pipeline capacity added during 1993 was developed to expand service to the Northeast and Western regions, particularly through import capacity from Canada.** The major additions completed in 1993 include projects by Northwest Pipeline, Pacific Gas Transmission, Empire State Pipeline, and CNG Transmission.

  —Northwest Pipeline Corporation increased its capacity by 433 MMcf per day, mainly to serve markets in the Northwest. The pipeline receives Canadian gas from Westcoast Energy, Inc. to serve customers in Washington, Oregon, Idaho, and Nevada. The company also has access to Rocky Mountain gas. A portion of its capacity is committed to moving Canadian gas to Pacific Gas Transmission.

  —After nearly 5 years of planning and construction, Pacific Gas Transmission began service on its 900 MMcf per day expansion that extends from the U.S./Canadian border to California. The line increases the company's capability to transport Canadian gas to more than 2.4 billion cubic feet per day.

  —Completion of the 155-mile Hinshaw-exempt[24] Empire State Pipeline from the Canadian border into New York State expands import capacity by at least 260 MMcf per day. However, most of the gas will be U.S. production transported to Canada through Great Lakes Transmission and then imported at Grand Island, New York, to serve utilities and electric power producers. Capacity on the line is expected to double in the late 1990's.

  —Markets in the Northeast have access to another 380 MMcf per day of capacity from the Southwest with the completion of CNG Transmission's portion of the "ANR Phase II" project, which in total has added about 1 billion cubic feet (Bcf) to daily delivery capability in the Northeast since 1991.

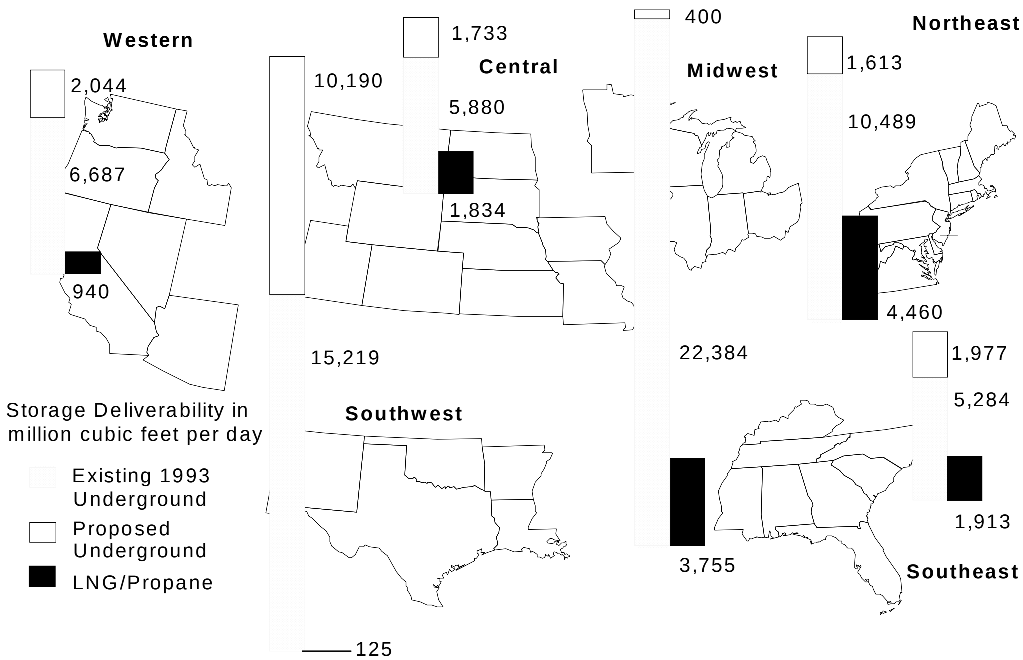
- **Increasingly, companies are proposing projects that link production, storage, and transmission facilities at market centers and provide additional delivery and receipt points.** Some construction is planned to support new "packaged" transportation services as companies respond to market opportunities resulting from the unbundling of transportation and storage services. In several cases, the projects are joint ventures of interstate pipeline companies, utilities, and the large local distribution companies who now must make their own arrangements for obtaining capacity.

- **Concerns about market uncertainties, surplus of capacity in some areas, and the potential inability to recover construction costs have led to a slowdown in capacity expansion.** At least eight projects planned for completion between 1992 and 1994, representing 2.6 Bcf per day of capacity, have been canceled or indefinitely postponed.[25] Four of these projects (totaling 1.5 Bcf per day) had been approved by the Federal Energy Regulatory Commission (FERC) under "at-risk" conditions.[26] A related issue is the future rate treatment for new facilities—whether costs are to be rolled into the rates charged all customers or recovered (through incremental pricing) only from those shippers utilizing the new facilities. Both the at-risk conditions and the uncertain rate treatment may increase the difficulty of obtaining financing.[27]

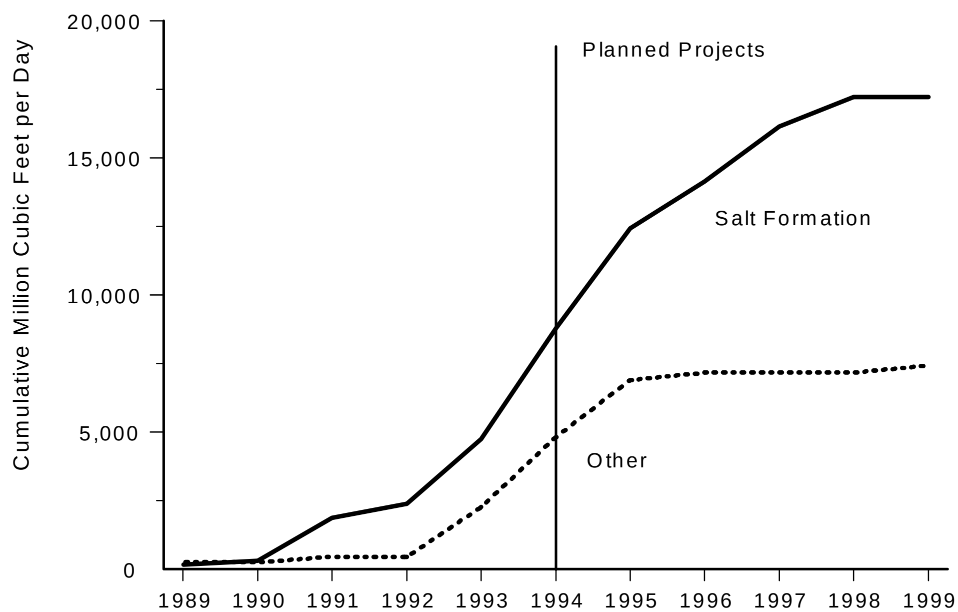
- **The existence of a secondary market for released capacity may reduce the need for new capacity.** Under Order 636, FERC's requirements for flexible receipt and delivery points and creation of a capacity release market allow shippers to resell (permanently or temporarily) unneeded capacity. Reselling of capacity should enable shippers to use the existing grid more efficiently, thus decreasing the need to build new facilities.

The operational flexibility of the pipeline network has been enhanced by the expanded access to underground storage under Order 636. Increased access to underground storage, combined with the storage deliverability additions planned within the next few years, will allow more extensive use of the interstate pipeline system.

Figure 10. Storage Is a Key Factor in Meeting Peak Demand



Development of new salt cavern storage projects will substantially increase peak-day storage deliverability



LNG= Liquefied natural gas.

Sources: Energy Information Administration. **1993:** EIA-191/FERC-8, "Underground Natural Gas Storage Report;" **1994-1999:** Energy Information Administration, Office of Oil and Gas, "Proposed Natural Gas Storage Projects," draft data base based on Federal Energy Regulatory Commission filings and information from various industry news sources.

Deliverability: Natural Gas Storage

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

While the implementation of Order 636 is a major milestone in the restructuring of the underground storage industry, the marketplace itself had already induced significant change. Most notable has been the dramatic increase in planned and recently developed storage capacity. Most of this new storage is salt cavern or other high-deliverability type storage where gas can be injected and withdrawn on a continuing basis throughout the year to balance daily or monthly demands. Since 1989, deliverability additions from salt cavern storage have been more than double those from other types of storage, and will far outstrip other storage deliverability additions through the end of the decade (Figure 10). Furthermore, investments in salt cavern storage account for more than 40 percent of the $2.2 billion projected for storage development between 1994 and 1999 (Chapter 4).

- **Planned storage expansions will increase peak-day deliverability from underground storage facilities by 27 percent by the end of the decade.** More than two-thirds of the 18-billion-cubic-feet-per-day increase is expected from "high-deliverability" facilities. As the number and variety of contractual arrangements have increased in the market, storage will be used to adjust for system imbalances, provide emergency supply backup, and support the new no-notice service required under Order 636.

- **The majority of new storage projects and the bulk of additional daily storage deliverability (77 percent) are slated to be developed in the supply areas of the Central, Southwest, and Southeast regions** (Figure 10). More than 77 percent of the planned storage in these regions is high-deliverability as these regions have the appropriate geology. These regions also have numerous pipeline interconnects already in place that will support the evolving market hubs. These storage additions will, for the most part, be used to supply customers in major market areas such as the Northeast and Midwest.

- **Approximately one-half of the 45 new sites proposed for development by 2000 are expected to tie into market hubs or have access to multiple pipeline systems.** Such locations enhance pipeline service and transportation flexibility as well as pipeline capability to support no-notice service.

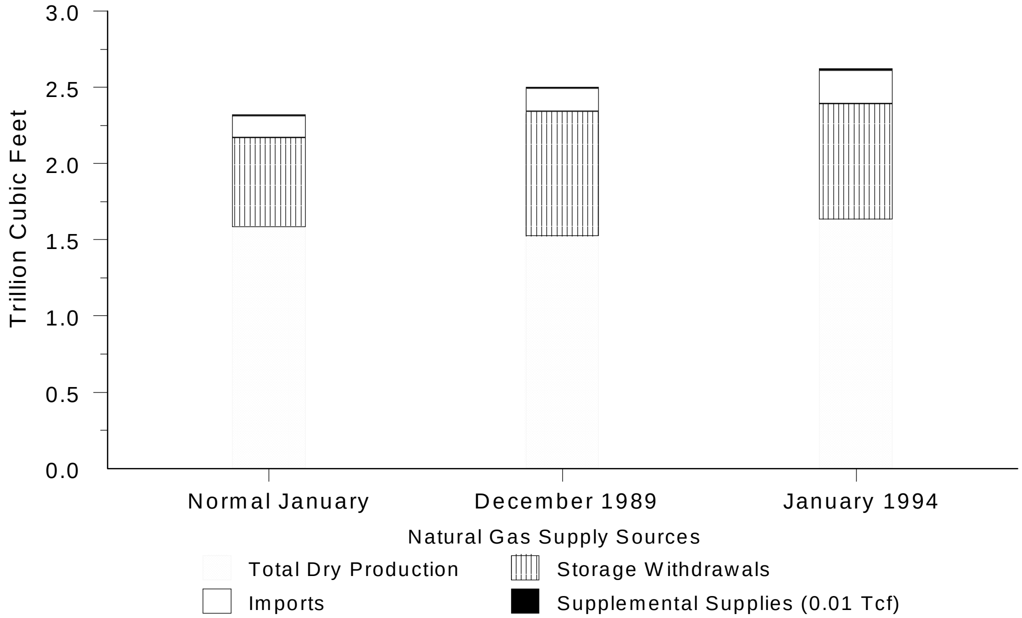
- **The level of proposed storage development in market areas is small (15-percent growth in deliverability in the Northeast Region, 2-percent in the Midwest), compared with planned supply area increases.** But these regions, which often have extreme variations in climate and large numbers of residential customers, already have an extensive infrastructure of storage facilities, as well as liquefied natural gas (LNG) and propane peaking facilities.[28] These peaking facilities are capable of providing up to 4.5 and 3.8 billion cubic per day, respectively, of supplies to the Northeast and Midwest regional networks on a short-term basis.[29]

- **High-deliverability storage provides a risk-management tool.** For pipeline companies, it provides the ability to maintain system reliability with supplies for emergency backup and load balancing. For producers and marketers, it provides inventory for hedging price variations and physical backup for futures market trading.

The overall growth in individual customer transactions and varying transportation arrangements has created more frequent system imbalances and the need for a quick response mechanism to manage operations. High-deliverability storage is becoming a key factor in servicing these needs and supporting overall system deliverability.

Figure 11. Total System Deliverability Can Support Market Growth

The natural gas system can respond to stress conditions in a variety of ways



The production and delivery system could support a 25.7 Tcf market by 1995

Estimated U.S. Capability to Deliver Natural Gas

Year	Annual Tcf	Peak Day Bcf/d
1991	24.0	119.6
1995	25.7	126.2

Tcf = Trillion cubic feet. Bcf/d = Billion cubic feet per day.

Notes: Storage withdrawals for December 1989 include both underground storage and liquefied natural gas storage. Other months are underground storage only. Supplemental supplies include synthetic natural gas, propane air (for peak shaving), refinery gas, biomass gas, air injected for stabilization of heating content, and manufactured gas commingled and distributed with natural gas. Normal January (January 1988) is determined by heating degree data from the National Oceanic and Atmospheric Administration.

Sources: Energy Information Administration. **Normal January:** *Historical Monthly Energy Review*, 1973-1988. **December 1989:** *Natural Gas Monthly*, January 1992. **January 1994:** *Natural Gas Monthly*, March 1994. **Deliverability:** National Petroleum Council, *The Potential for Natural Gas in the United States: Transmission and Storage*, Vol. IV, December 1992.

Deliverability: Total System Deliverability

The natural gas industry is now viewing the integrated production, delivery, and storage system with an increased awareness of the roles of each component. Critical to this understanding is an appreciation for the flexibility, capability, and balance that must be struck between the components of total system deliverability. These components include: sufficient productive capacity (from both domestic and imported sources); adequate transmission and delivery systems; accessible storage; and other services that maintain system integrity (such as balancing, linepacking, and peak-shaving ability).

A primary focus of the natural gas industry throughout the restructuring process has been to maintain the capability to satisfy consumers' current and potential service requirements, which vary over time. Equally important is the industry's ability to respond to variations in operating conditions on the system.

- **An important management goal for pipeline companies and local distribution companies is achieving a well-balanced load to keep their systems operating at high rates of capacity utilization year-round.** Transmission and delivery systems are most efficient when they operate close to capacity (i.e., high utilization rates). Strategic use of storage capacity can increase overall system utilization rates and system efficiency because it is a means of equalizing pipeline flow levels throughout the year—e.g., using excess pipeline capacity during periods of low demand to deliver gas into storage. Higher pipeline utilization rates can also be achieved by serving multiple markets with load diversity. The increased access to markets resulting from industry restructuring has potential in this area.

- **The production and delivery system has shown flexibility and resilience in responding to stress conditions.** Normal supply patterns may not be sustainable during periods of stress. Technical limits on the surge capacity of producing gas wells mean that sharp increases in demand have to be met from storage, imports, or peaking facilities. In January 1988, a normal winter month,[30] 68 percent of supplies were provided by field production, 25 percent from storage, 6 percent from imports, and 1 percent from supplemental supplies including peak shaving (Figure 11).

  However, in December 1989, severely cold weather[31] caused some well freezeups, thus the share of supplies from production declined to 61 percent. To compensate, a record 822 billion cubic feet (Bcf) was withdrawn from storage, supplying 33 percent of the month's total. Imports again provided 6 percent that month.

  During the frigid weather in January 1994, field production hit a record monthly level, but provided only 62 percent of supply. (Field production may have been constrained from even higher levels because of today's smaller margin between production and productive capacity than during the 1980's.) Storage was again called upon heavily, providing 29 percent of supply with the second highest withdrawal level recorded. The industry was also able to draw on expanded import capacity, which was 50 percent higher than in December 1989, to provide 8 percent of supplies.

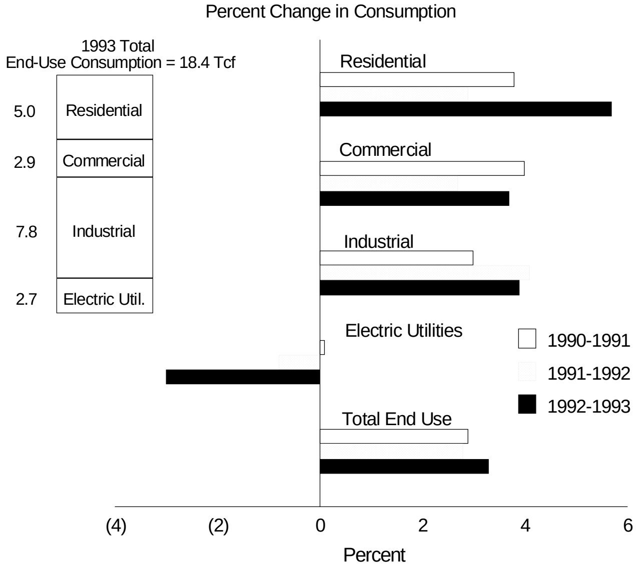
- **The U.S. natural gas system can currently deliver 25 trillion cubic feet (Tcf) per year and approximately 124 Bcf on a peak day.**[32] Existing interstate pipeline and storage facilities can support a growing U.S. market. The National Petroleum Council estimates that by 1995, total U.S. deliverability is expected to increase to nearly 26 Tcf per year, approximately 126 Bcf on a peak day (Figure 11).[33] These estimates are based on an analysis of existing facilities/capabilities and an assessment of incremental supply and capacity additions.

- **Storage facilities will continue to be the critical link in the production and delivery system.** High-deliverability storage, in particular, is a key factor in the ability of the industry to satisfy market growth. Storage is used throughout the year to achieve a balance between the relatively constant supply from production areas and wide seasonal variation in demand. Over the shorter term, storage is being used in conjunction with peak-shaving supplies to meet short-term demand swings, which may be daily or hourly.

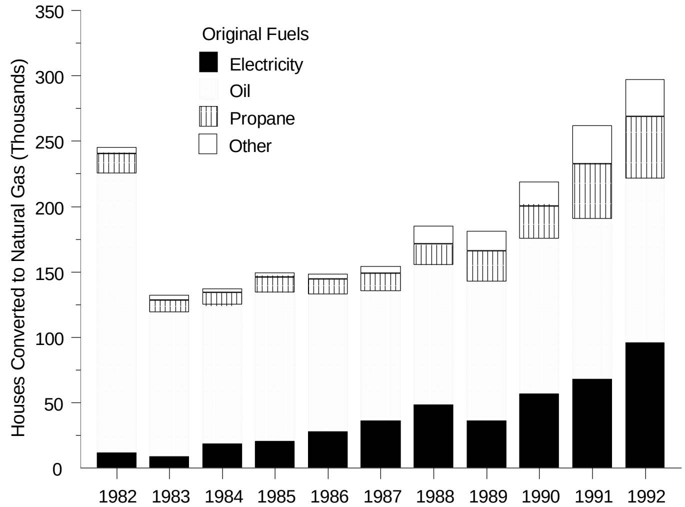
In a changing market, the pipeline companies' focus on delivery capability and reliability requires them to ensure the integrity of their system and at the same time be able to respond flexibly to customer needs.

Figure 12. End-Use Consumption and Prices Increased in 1993

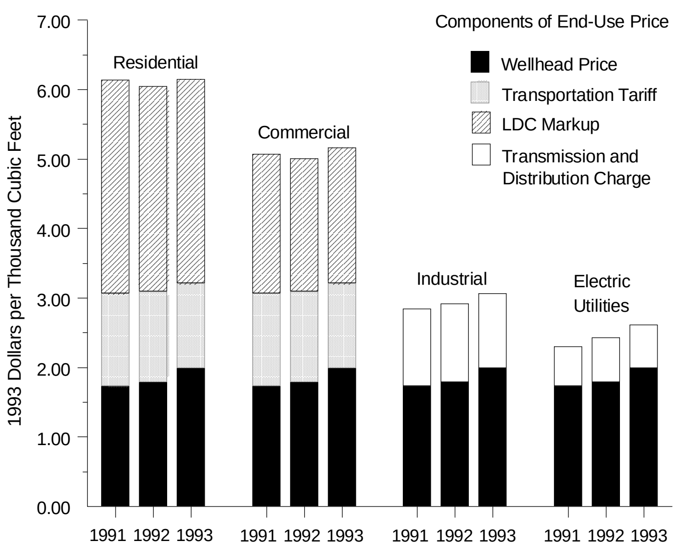
Most sectors consumed more gas in 1993



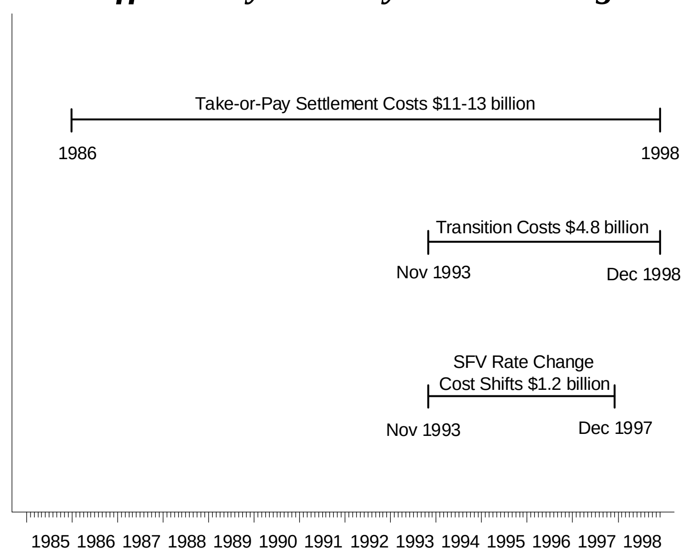
Residential increases were aided by housing conversions



LDC markups were relatively flat in 1993



End-use prices will continue to be affected by industry restructuring



Tcf = Trillion cubic feet. LDC = Local distribution company. SFV = Straight fixed variable.

Notes: Industrial end-use price data represent onsystem sales only. This share for 1991 was 33 percent; for 1992, 30 percent; and estimated for 1993, 28 percent. Also, "Other" housing conversions includes coal, wood, and nonclassified conversions.

Sources: **Consumption:** Energy Information Administration (EIA), *Natural Gas Monthly*, April 1994. **Percent Change in Consumption:** EIA, Office of Oil and Gas: derived from: *Natural Gas Monthly*, April 1994. **Househeating Conversions:** American Gas Association, *Residential Natural Gas Market Survey 1992*, June 1993. **End-Use Price Components:** EIA, Office of Oil and Gas: derived from: Wellhead, City Gate, and End-Use Prices: *Natural Gas Monthly*, April 1994. **Take-or-Pay Costs:** EIA, Office of Oil and Gas; estimated based on FERC Order 636 (B). **Transition Costs and Cost Shifts:** Government Accounting Office, *Report on Natural Gas Costs, Benefits, and Concerns Related to FERC's Order 636*, November 1993.

End Use: Natural Gas Consumption and Price

End-use natural gas consumption increased by 3 percent from 1992 to 1993, reaching 18.4 trillion cubic feet (Tcf). The increase was largely driven by growth in the industrial and residential sectors. Industrial use rose 292 billion cubic feet (Bcf) (4 percent) in 1993 while residential use increased comparably (266 Bcf or 6 percent) (Figure 12). In contrast, gas use by electric utilities declined for the second year in a row. Residential and commercial users saw price increases of 4 and 6 percent from 1992 to 1993, with prices reaching $6.15 per thousand cubic feet (Mcf) and $5.16 per Mcf, respectively. Price increases were steeper in the industrial and electric utility sectors where the 8- and 11-percent increases from 1992 resulted in 1993 prices of $3.07 and $2.61 per Mcf, respectively.

- **The return to normal weather (on average) in 1993 sparked increases in the residential and commercial sectors where consumption rose in 1993 to 5.0 and 2.9 Tcf, respectively.** The winter of 1992-93 ended the pattern of warmer-than-normal weather during the previous three winters. The weather effect was particularly acute in March 1993 as the "Storm of the Century" swept across the eastern part of the Nation. March consumption alone accounted for approximately half of the 1993 increase in each sector, and was the highest March level since monthly data have been collected (beginning in 1973). The severe cold spell in January 1994 resulted in the highest monthly consumption ever recorded for these sectors—1.0 Tcf residential, and 0.5 Tcf commercial.

  Residential and commercial gas consumption are also affected by the number of homes and commercial facilities heated by natural gas. The proportion of new homes heated with gas has increased steadily during the past several years, reaching 65 percent of all single-family homes built in 1992. Conversions from other fuels further augmented the gas-heated housing stock each year (Figure 12).[34] In 1992, for example, 621,000 new homes were gas heated, while 297,000 existing homes converted to gas heat. Had it not been for the increasing efficiency of gas use (the average residential customer used 15 percent less gas in 1992 than 10 years earlier, and the average commercial customer used 26 percent less),[35] gas consumption growth would have been even stronger in these sectors.

- **Industrial gas use increased to 7.8 Tcf in 1993—a level not seen since 1974.** Natural gas use by nonutility generators (NUG's) has contributed to consumption in this sector for many years. NUG gas consumption increased in 1992, the most recent year's data, reaching 1.8 Tcf, compared with 1.6 Tcf in 1991.[36] However, demand for electricity in two of the busiest NUG growth markets, the Northeast and California, is now flat or decreasing because of overcapacity and economic recession.

- **Electric utility consumption declined 3 percent to 2.7 Tcf in 1993.** Coal, nuclear, and hydroelectric power all replaced some natural gas in 1993, in part because of higher gas prices to electric utilities in the first half of the year and because record rainfall in some areas of the country increased hydroelectric generation.

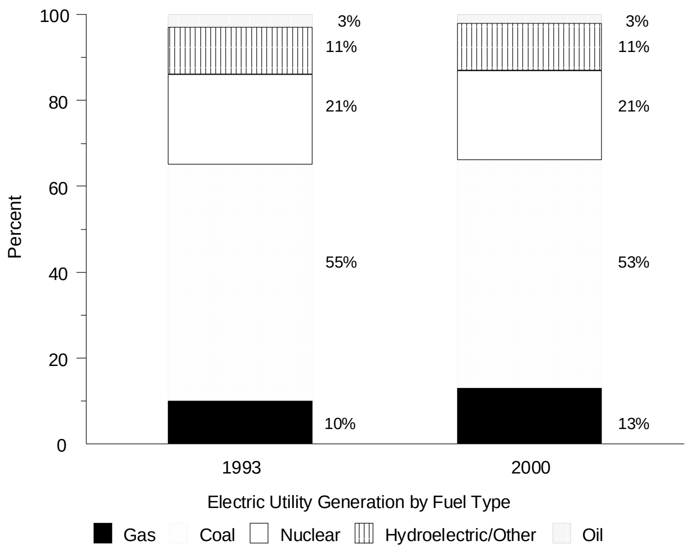
- **Changes in local distribution company (LDC) markups leveled off in 1993 (Figure 12).** After dropping 4 percent in real terms from 1991 to 1992 in both the residential and commercial sectors, LDC markups in these sectors remained virtually flat in 1993. In contrast the combined transportation and LDC markups in the industrial and electric utility sectors declined 4 and 3 percent, respectively, after having increased in 1992 (most significantly by 12 percent for electric utilities). Changes in markups reflect industry adjustments to the changing natural gas marketplace. For example, downward pressure on LDC charges may be attributed to increased efficiencies as LDC's attempt to remain competitive suppliers of natural gas and retain customers that have fuel-switching capability.

- **Costs associated with the restructuring of the natural gas industry will continue to affect consumer prices through 1998.** These costs include take-or-pay settlement costs, cost shifts among consuming sectors resulting from the Order 636 change to straight fixed-variable rates, and the general transition costs of Order 636 (Figure 12). These costs are expected to have an impact on delivered prices through the late 1990's.[37] The extent of the impact will be strongly influenced by the mitigation procedures required by Order 636, by State regulatory agency actions, and by company actions to offset some of the impacts, for example, by taking advantage of capacity release mechanisms (Chapter 2).

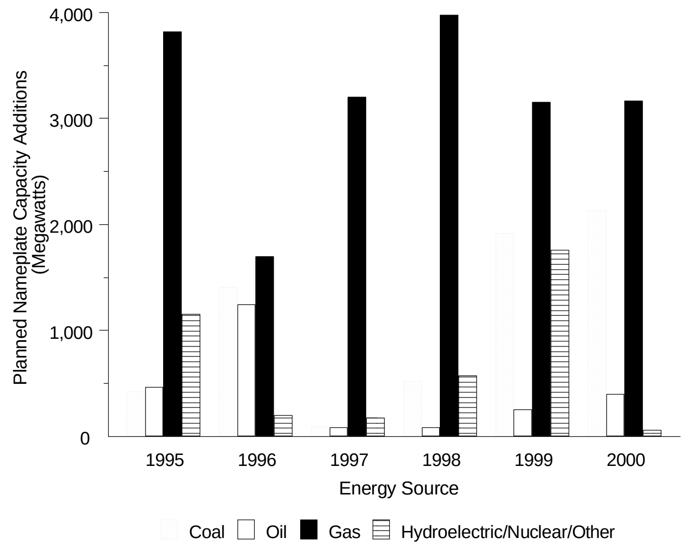
Future patterns in gas consumption are expected to differ from recent trends, particularly in the electric generation and residential markets.

Figure 13. Future Trends in End-Use Markets

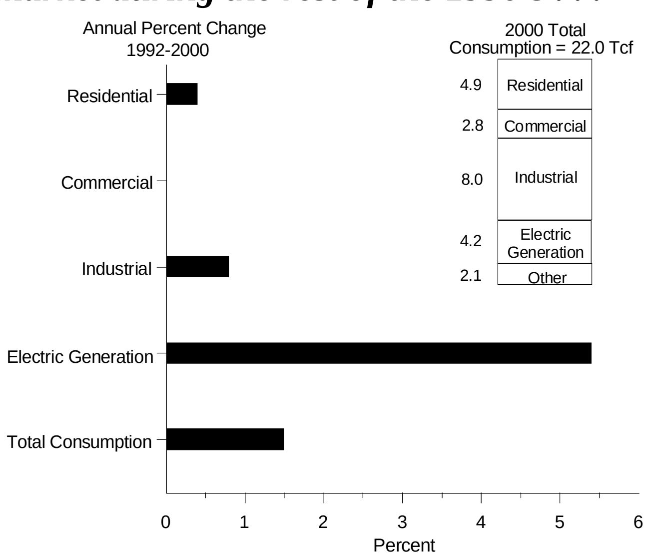
Natural gas is expected to be a larger share of electric utility generation fuel . . .



. . . As new utility generating capacity is increasingly dominated by gas-fired plants



Electric power will be the fastest growing market during the rest of the 1990's . . .



. . . As natural gas prices remain competitive with other fuel prices

Fuel Prices to Electric Utilities (1992 Dollars per Million Btu)

Fuel	1992	2000
Distillate	4.51	4.84
Residual	2.51	3.48
Natural Gas	2.28	2.92
Coal	1.41	1.63

Tcf = Trillion cubic feet.

Notes: Sum of shares may not equal 100 percent because of independent rounding. "Other" electric utility generation fuels include pumped storage, methane, propane, and blast furnace gas; and geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power. "Other" new generating capacity includes refuse, steam, solar, and waste heat. "Electric generation" in lower left graph includes electric utilities and nonutility generators, and excludes cogenerators. "Residual" fuel oil prices are a quantity-weighted average price for low-sulfur and high-sulfur residual fuel oil.

Sources: Energy Information Administration. **Fuel Shares in Electric Utility Generation:** Office of Oil and Gas, derived from: *Annual Energy Outlook 1994*, National Energy Modeling System, Reference Case, run AEO94B.D1221934. **Planned Capacity Additions:** *Inventory of Power Plants in the United States 1992*, October 1993. **Projected Growth Rates:** Office of Oil and Gas, derived from: *Annual Energy Outlook 1994*. **Consumption and Fuel Prices for Electric Utility Generation:** *Annual Energy Outlook 1994*.

End Use: Future Trends in Consumption and Price

Natural gas consumption is expected to continue to grow well into the 21st century. Much of this growth will be driven by environmental considerations as well as by the increased competitiveness within the natural gas market. Recent growth has been dominated by cogeneration applications in the industrial sector and weather-induced increases in the residential sector. Future growth will be concentrated in electricity generation (Figure 13).[38]

- **Total natural gas consumption is projected to increase by more than 1 percent per year from 1992 through the end of the century, reaching 22 trillion cubic feet by 2000.** The electric power sector[39] is expected to show the highest growth, exceeding 5 percent per year, followed by the industrial sector at 1 percent. Residential gas demand is expected to grow by only 0.4 percent per year, and no growth is forecast for the commercial sector as efficiency gains are projected to offset market growth.

- **Gas demand for electric utility generation will grow largely because of economic and environmental advantages of natural gas over other generating fuels.** The majority of new generating facilities built by electric utilities are expected to be gas-fired, primarily combined-cycle plants and combustion turbines. These units are more efficient, less capital-intensive, available in a wide range of capacities, and can be constructed more quickly than alternative units that burn either coal, residual fuel oil, or distillate fuel oil. Approximately 60 percent of the planned generating capacity additions from 1995 through 2000 are expected to be gas-fired.[40]

  A potentially significant market is electric utility repowering projects that will upgrade existing gas-fired power plants and convert oil- and coal-fired plants to natural gas or co-firing capability. Repowering has an advantage over new construction in that it involves fewer permit approvals, shorter lead times, and may have lower construction costs. A plant can often be repowered at a higher capacity and higher efficiency than the original design. Although utilities have reported few planned repowering projects, by some industry estimates, as much as half of the growth in gas consumed in the electric power sector could come from repowered units.[41]

- **Growth in industrial gas demand (including cogeneration) will continue at a modest pace,** restrained by technological advances in industrial processes, the use of more efficient equipment, and a shift in the composition of the U.S. industrial base. The industrial base is moving away from energy-intensive industries, such as iron and steel, to less energy-intensive industries, such as electronics and pharmaceuticals.

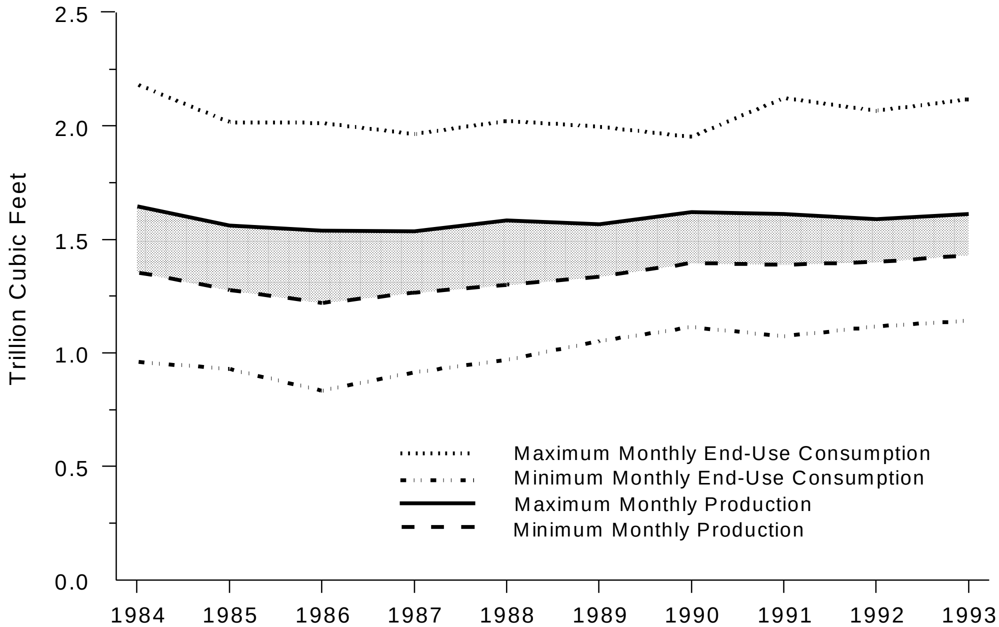
- **Residential and commercial gas consumption is expected to grow slowly as increased market penetration in these sectors is offset by higher energy efficiency.** Any greater growth would depend on the success of new products, such as gas cooling, heat pumps, and fuel cells. Gas currently has a very small share of the residential and commercial cooling market, accounting for only 3 percent of the nearly 1 quadrillion Btu market.[42]

- **The transportation sector is getting more attention from the natural gas industry as it promotes natural gas vehicles.** At present, approximately 30,000 natural gas vehicles consume less than 1 billion cubic feet (Bcf) of gas. This is projected to increase to 130 Bcf by 2000,[43] assuming the industry can overcome cost and safety concerns[44] and expand the network of refueling stations. (The network of approximately 800 refueling stations compares with over 200,000 gasoline outlets.[45]) Tax incentives provided by the Energy Policy Act of 1992, State initiatives to promote alternate fuel vehicles for air quality improvement, and the Department of Energy's "Clean Cities" program[46] will encourage growth in this sector.

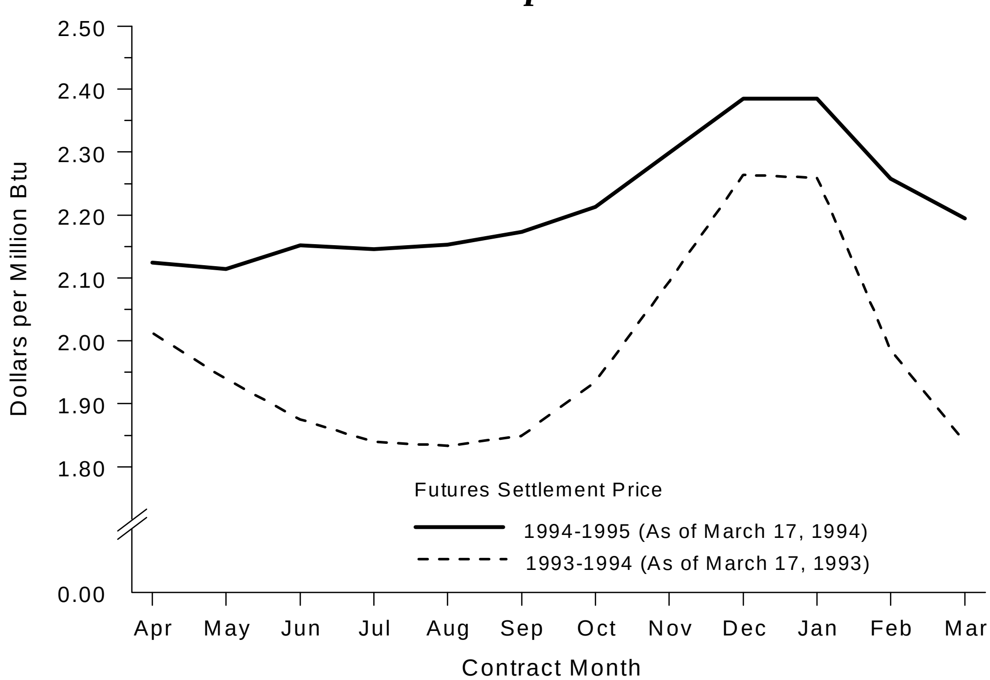
Retail natural gas prices are projected to remain competitive with petroleum prices, increasing by 2.5 percent (in real terms) per year on average from 1992 through 2000. This projection shows that competition in the electricity sector between natural gas and residual fuel oil will continue to be a limiting factor for natural gas price increases (Figure 13). A number of developments could work to increase gas prices above this projection, however. One such development could be higher State taxes on residual fuel oil, other environmentally motivated actions to discourage the use of residual fuel oil, or the disappearance of dual-fired gas/residual oil power plants from the stock of generating facilities. Virtually all new gas-fired plants are dual-fired with distillate fuel oil, which commands a much higher price than residual oil. If the primary competitor to gas becomes distillate rather than residual oil, there may be opportunity for upward movement in the market price of natural gas, depending on the intensity of competition within the gas industry.

Figure 14. Outlook

Seasonal variation in production and consumption is diminishing



Futures prices indicate a similar trend is expected in wellhead prices



Sources: **Consumption and Production:** Energy Information Administration, Office of Oil and Gas: based on: *Natural Gas Monthly*, historical data series. **Futures Prices:** Commodity Futures Trading Commission, Division of Economic Analysis.

Outlook

Although the restructuring under Order 636 promises more change, significant progress toward a more streamlined and efficient industry has already been made under the deregulatory process started more than a decade ago. This has resulted in a reduction in the seasonality of some aspects of the market (Figure 14).

- **One striking development during the past year has been the absence of a strong seasonal pattern in average wellhead prices**. There are indications that this reduction in seasonality is expected to continue into 1995. For example, futures contract prices in 1994 (as of March 17, 1994) show a moderated seasonal pattern with a winter peak but no significant trough in the off-peak months when compared with futures prices a year earlier. As price variability between months is reduced, price risk declines.

- **Reduced seasonality is also evident in gas production and consumption.** Over the past decade, the differences between the highest and lowest monthly levels of consumption and production have been gradually declining. In 1984, the difference in consumption between the highest and lowest month was 1.2 trillion cubic feet (Tcf). Since 1988, the difference has been, with one exception, less than 1 Tcf, a 20 percent or more reduction. A similar pattern has developed with production. In 1984, the difference between the highest and lowest monthly production levels was about 300 billion cubic feet (Bcf). Since 1991, the difference has been less than 200 Bcf.

- **An important aspect of this change has been the increased utilization of storage,** as both injections and withdrawals of gas have increased throughout the year. This allows more constant wellhead production and contributes to higher utilization of production and transmission facilities.

Regulatory restructuring has better equipped the industry to maintain its current markets and compete for new markets. Financial success in the gas industry is now increasingly aligned with the ability of firms to compete in the marketplace: competing with other gas companies to develop better services to meet the needs of customers and competing with suppliers of alternative fuels to capture new markets.

- **The natural gas market has substantial growth potential and is projected to expand by 2 trillion cubic feet between 1993 and 2000.**[47] Much of the growth is expected in the electric generation[48] and industrial markets as a result of the economic and environmental advantages of natural gas over other generating fuels. For some companies, environmental concerns dictate the use of natural gas. Achievement of substantial growth will depend on the ability of the industry to develop new services to expand electric power and cogeneration markets and keep the cost of gas competitive with alternative fuels.

- **Electronic information transfer will play a large role in reducing the transaction costs associated with the complex contracting and tracking of gas flows required in the new market.** In this new contracting environment, all parties, from producers to end users, must be knowledgeable of the entire system to use it effectively. Access to timely information increases market transparency, provides users with more choices, and enables users to make the choice that best suits their needs. As buyers and sellers gain expertise operating in the new structure, transaction costs will decline and consumers will benefit even more from an efficient system directly responding to their needs.

- **There has been a reallocation of risk under Order 636, as well as an overall increase in risk associated with the greater reliance on market forces.** The evaluation of these risks and their potential impact on business operations has become an increasingly important aspect of the gas industry. Services and strategies to manage these risks are available with more specialized services being continually developed. As market participants address their risk exposure, they can substantially protect their revenue stream.

The opportunities available to the industry are substantial. The new industry structure that has evolved under Order 636 has placed the natural gas industry in a better position to compete for market share domestically. In addition, the U.S. gas industry is increasing its investment overseas to take advantage of foreign gas reserves and a large potential market.[49] The performance of natural gas firms will be determined by their ability to adapt to the new business environment while maintaining competitive prices and reliable service.

Endnotes

1. Under the Natural Gas Policy Act of 1978, gas from newly drilled wells was sold at a substantial premium relative to gas from existing wells. For more information on this point, see Energy Information Administration, *Drilling and Production Under Title I of the Natural Gas Policy Act: 1978-1986*, DOE/EIA-0448(86) (Washington, DC, January 1989).

2. Infill drilling is the process of drilling new wells between producing wells in older fields to extract additional supply. Traditionally, gas wells were drilled on 640-acre spacing to avoid potential damage to the reservoir from overproduction and to protect landowner's property rights. However, reservoir studies conducted during the 1980's indicated that much additional gas could be recovered from some fields by reducing the well spacing. Infill drilling programs have resulted in many fields being produced using 320-acre and even 80-acre spacing.

3. Energy Information Administration, "Natural Gas Productive Capacity for the Lower 48 States: 1980 through 1995," draft report.

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

5. For further information on 3-D seismic survey methods, see Energy Information Administration, R. Haar, "Three-Dimensional Seismology—A New Perspective," *Natural Gas Monthly*, December 1992, DOE/EIA-0130(92/12) (Washington, DC, December 1992); and D. George, "3-D Volume Interpretation to Revolutionize Computer-Aided Exploration and Development," *Offshore/Oilman Magazine* (September 1993).

6. For further information on PDC drill bits, see "PDC Drill Bits Design and Field Application Evolution," *Journal of Petroleum Technology* (March 1988) pp. 327-332.

7. Energy Information Administration, *Drilling Sideways—A Review of Horizontal Well Completion Technology and its Domestic Application*, DOE/EIA-TR-0565, Technical Report (Washington, DC, April 1993).

8. Fracturing is the process of pumping fluids under high pressure into the reservoir to "fracture the rock" and increase gas and oil flow rates. For further information on fracturing technology, see R.V. Flatern, "Fracturing Technology Poised for Rapid Advancement," *Petroleum Engineer International* (October 1993); and A.S. Abou-Sayed, "The Changing Face of Hydraulic Fracturing Improves Reservoir Management," *Petroleum Engineer International*, Supplement (October 1993).

9. The resource base estimate is based on technological advances expected by 2010.

10. S.A. Wheeler and others, "Low-Risk Approach to Deepwater Development Proposed," *Offshore/Oilman Magazine* (January 1993).

11. Data in this discussion are derived from data used for the U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports*, First Quarter - Fourth Quarter 1993. The total 1993 imports from Canada from this source exceed the Energy Information Administration estimate of 2.2 trillion cubic feet by 2.3 percent.

12. The controversy was triggered by the California Public Utility Commission's adoption of new natural gas procurement rules, including a capacity release program on Pacific Gas Transmission, effective August 1, 1991. Canadian producers argued the capacity release program would adversely affect their long-term contracts for gas destined for Pacific Gas and Electric Co. and its customers. The National Energy Board order was instituted to prevent short-term (and lower priced) exports from displacing the long-term supplies already under contract.

13. The National Petroleum Council (NPC) estimate is approximately three times the U.S. Geological Survey estimate, which only considered gas from conventional sources and hence excluded gas from nonconventional categories such as coalbed methane and gas from tight formations. It is about 5 to 20 percent larger than other estimates that do consider these sources of supply. For instance, the Energy Information Administration (EIA) estimate was 904 trillion cubic feet (Tcf) as of December 31, 1988 (*The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National*

Energy Strategy, SR/NES/90-05 (Washington, DC, December 1990)), while the Potential Gas Committee's latest mean estimate was 1,001 Tcf ("Potential Supply of Natural Gas in the United States, December 31, 1992"). The NPC estimate differs mainly in its assessment of reserve appreciation and nonconventional gas. It should also be noted that the NPC estimate includes gas resources that are currently off limits because of political or institutional constraints. Economically recoverable volumes of natural gas within the lower 48 States affected by access restrictions are estimated to be between 7.6 and 11.5 Tcf. For more information see EIA, *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy*.

14. The statement that additional supplies from these areas are not expected prior to 2010 is based on data used for Energy Information Administration, *Annual Energy Outlook 1994 (AEO)*, DOE/EIA-0383(94) (Washington, DC, January 1994); specifically, the National Energy Modeling System, Reference Case, run AEO94B.D1221934, and High Economic Growth Case, run HMAC94.D1221932; and *Supplement to the Annual Energy Outlook 1994 (Supplement)*, DOE/EIA-0554(94), p. 49. The *Supplement* provides the assumptions regarding potential construction of the Alaskan Natural Gas Transportation System (ANGTS). ANGTS is assumed to be brought on line when the appropriate border-crossing price is reached for gas delivered to the lower 48 States. The price for the first phase is $3.55 per thousand cubic feet (1992 dollars). This price is not reached in the Reference Case prior to 2010, therefore, supply from Alaska via ANGTS will not be available prior to 2010. However, under the assumptions contained in the High Economic Growth Case, the $3.55 border-crossing price is reached prior to 2010, and therefore supply via ANGTS is available in the latter part of the decade.

15. A.D. Coen, "Subsalt Prospects Add Zest to Gulf of Mexico Lease Sale," *Oil and Gas Journal* (April 11, 1994).

16. For additional details on the relationship between spot and futures prices, see John H. Herbert, Office of Oil and Gas, Energy Information Administration, "An Analysis of Average Cash Prices and Futures Prices for Natural Gas," Draft Working Paper # 4 (Washington, DC, December 1993).

17. All data on natural gas and other futures markets and exchange of futures for physicals were obtained from the Commodity Futures Trading Commission, Division of Economic Analysis.

18. Peter Fusaro, "Insurance? No Obstacle," *Energy Risk*, Vol. 1, No. 1 (February 1994), p. 14.

19. See Chapter 3 for definition and further discussion of natural gas options and swaps.

20. Gas wheeling is a service whereby gas is transferred between pipelines at a common market hub. This service is helpful in the event of emergency shutdowns on one or more pipelines.

21. Parking is the short-term, interruptible storage of natural gas at a market hub. Techniques such as linepacking are used to store gas at the hub itself rather than transferring the gas to an underground storage facility.

22. Pasha Publications Inc., "March Sees Record Amounts of Released Capacity," *Gas Transportation Report*, Vol. 3, No. 11 (March 16, 1994), p. 2.

23. Interstate Natural Gas Association of America, "Interstate Natural Gas Pipeline Performance During the Cold Snap of January 1994," (March 1994).

24. As a Hinshaw-exempt (intrastate) pipeline company, Empire State Pipeline is subject to regulation by the New York Public Service Commission. The Federal Energy Regulatory Commission authorized Empire to site facilities at the U.S./Canada border.

25. The canceled projects include: Cornerstone (Endevco, 600 million cubic feet per day (MMcf/d)), Delta Pipeline (200 MMcf/d), Line ACE (Arkla, 350 MMcf/d), Ozark Expansion (160 MMcf/d), Questar Loop (153 MMcf/d), Oklahoma-Arkansas Line (500 MMcf/d), Valley Line Expansion (Colorado Interstate, 116 MMcf/d), and West-to-East Crossover (Tennessee Gas, 535 MMcf/d).

26. Currently, FERC issues at-risk certificates for new construction unless the applicant has executed firm contracts and has market data demonstrating that present and future rate payers will be protected from having to make inappropriate contributions to the costs associated with the new facilities.

27. Under incremental rates, costs may be recovered only from rates charged to expansion shippers, who may underutilize the new facilities. Thus the pipeline company shareholders bear the risk for the success or failure of the project.

28. Underground natural gas storage inventory enables local distribution companies (LDC's) to meet peak customer requirements up to a point. Beyond that point, the distribution system still must be capable of meeting customers' short-term peaks and swings that may occur on a daily or even hourly basis. During periods of extreme usage, the peaking facilities, mostly liquefied natural gas and liquefied petroleum gas, as well as other sources of temporary storage, must be relied upon to supplement system and underground storage supplies. LDC's also use linepacking to meet peaking needs.

29. Gas Research Institute, *The Seasonal Demand and Delivery System for Natural Gas in the Lower-48 United States*, GRI Report No. 92/0475.

30. Temperatures in January 1988 were relatively close to normal for January, based on data for heating degree days from the National Oceanic and Atmospheric Administration.

31. In December 1989, weather east of the Rocky Mountains was 33 percent colder than a normal December, based on data for heating degree days from the National Oceanic and Atmospheric Administration.

32. This estimate was derived by the Energy Information Administration, Office of Oil and Gas, based on the estimates of delivery capacity in the National Petroleum Council's, *The Potential for Natural Gas in the United States: Transmission and Storage*, Vol. IV (Washington, DC, December 1992) and an assessment of changes in interregional capacity.

33. National Petroleum Council, *The Potential for Natural Gas in the United States: Transmission and Storage,* Vol. IV (Washington, DC, December 1992).

34. Gas used in new homes includes liquefied petroleum gas. Gas used in housing conversions is natural gas only. American Gas Association, *Residential Natural Gas Market Survey 1992* (Arlington, VA, June 1993), Table 1, p. 6 and Table 6, p. 12.

35. American Gas Association, *Gas Facts: 1992 Data* (Arlington, VA, 1993), Table 10-5, p. 128.

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

37. Note that a portion of the take-or-pay settlement costs is being absorbed by the interstate pipeline companies while the rest is being allocated to pipeline company customers, including end users and local distribution companies (LDC's). State agencies determine whether costs allocated to an LDC are passed on to the LDC's customers.

38. Electricity generators include electric utilities and nonutility generators (small power producers, independent power producers, and exempt wholesale generators as defined by the Energy Policy Act of 1992), which produce electricity for sale to the grid. Cogeneration is classified as an industrial activity.

39. The electric power sector includes electric utility and nonutility generators, and excludes cogenerators.

40. Based on Energy Information Administration, *Inventory of Power Plants in the United States 1992*, DOE/EIA-0095(92) (Washington, DC, October 1993), Tables 6-9, pp. 14-15.

41. Paul D. Holtberg and Larry Makovich, "Potential for Repowering in the Electric Generation Sector: Impacts on Natural Gas Demand," in *Proceedings, International Association for Energy Economics 15th Annual North American Conference* (Washington, DC, 1993), pp. 81-91.

42. Based on data used for Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994), Tables A-4 and A-5, pp. 60 and 62.

43. Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994), p. 70.

44. In early 1994, there were two reports of compressed natural gas cylinders rupturing on General Motors Corporation (GMC) Sierra pickup trucks. An investigation of the two incidents revealed that both ruptures were the result of stress corrosion cracking resulting from acid dripping from the truck bed onto the tank covering. In response to these incidents, GMC has canceled production of all natural gas vehicles (NGV's) for model year 1994 and offered to buy back all Sierra pickups sold for model years 1993 and 1994. GMC plans to continue producing NGV's for the following model year (Southwest Research Institute, *Executive Summary of Investigation of Compressed Natural Gas Cylinder Ruptures*, March 15, 1994).

45. Data on compressed natural gas refueling stations are as of 1993 and from American Gas Association, Office of Policy, Analysis and International Affairs. The information on gasoline outlets is from Hunter Publishing, *National Petroleum News* (Des Plaines, IL, April 1993).

46. The Department of Energy has initiated a voluntary "Clean Cities" program, that is designed to encourage the conversion of fleet vehicles to alternative fuel use (including natural gas) and to build the infrastructure of fuel supply needed for their operation. Aims of the program include putting 250,000 new alternative-fueled vehicles on the road and 500 to 1,000 refueling stations in 50 cities across the Nation by 1996. See Department of Energy, "Chicago, Albuquerque CLEAN CITIES Numbers 10, 11," *DOE This Month*, Vol. 17, No. 6 (Washington, DC, June 1994), p. 3.

47. Based on data used for Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994), National Energy Modeling System, Reference Case, run AEO94B.D1221934.

48. This includes electric generation by electric utilities and nonutility generators, and excludes cogenerators.

49. Caleb Soloman and Robert Johnson, "Natural Gas Industry Is Reinventing Itself by Going International," *Wall Street Journal* (April 19, 1994), p. A1. Gregg Jones, "Exxon chief sees natural gas fueling growth," *The Dallas Morning News* (April 28, 1994), p. 2D. David Pilling, "British Gas and Tenneco win Chilean pipeline deal," *Financial Times* (October 30, 1993), p. 2. Lawrence J. Speer, "Dallas firm to develop Peruvian gas field," *The Dallas Morning News* (March 31, 1994), p. 2D.

2. The Natural Gas Industry Under Order 636

Introduction

Order 636, issued by the Federal Energy Regulatory Commission (FERC) on April 8, 1992, has transformed the interstate natural gas pipeline industry. Under the order, interstate pipeline companies were required to separate their merchant and transportation functions by November 1, 1993, the unofficial start of the winter heating season. Oversight of gas sales and marketing activities has been significantly reduced, but sales by an interstate pipeline company and interstate transportation remain subject to FERC jurisdiction. The restructuring process has been closely supervised by FERC and has led to extensive changes throughout the natural gas industry.

- Corporate changes have occurred as pipeline companies have shed their sales functions or reorganized them into marketing subsidiaries.
- Additional marketing companies have formed to coordinate the sales and transportation services for customers who prefer that type of arrangement.
- Pipeline company customers with contracts for gas supply have now become shippers with contracts for pipeline transportation capacity; they must arrange separately to purchase the gas itself.
- Customers have had to become more knowledgeable about operational aspects of the pipeline industry, even as pipeline operations have been radically altered.
- Service options have become more flexible and diverse.
- Pipeline capacity can now be traded among customers in a capacity release program administered by the pipeline companies.
- Changes in pipeline rates have affected how services are priced and who pays for them. Each service now has a separate charge, and transportation and storage rates are generally required to follow the straight fixed-variable (SFV) rate design methodology.
- Industry restructuring has resulted in an additional $2 billion in transition costs thus far.
- Electronic bulletin boards are the main link between customers and pipeline companies, allowing transactions to be rapidly and efficiently completed.

As a result of these changes, the natural gas industry has become more competitive and market-driven. In addition, Order 636 has substantially shifted the risks of doing business in the gas industry among the market participants.

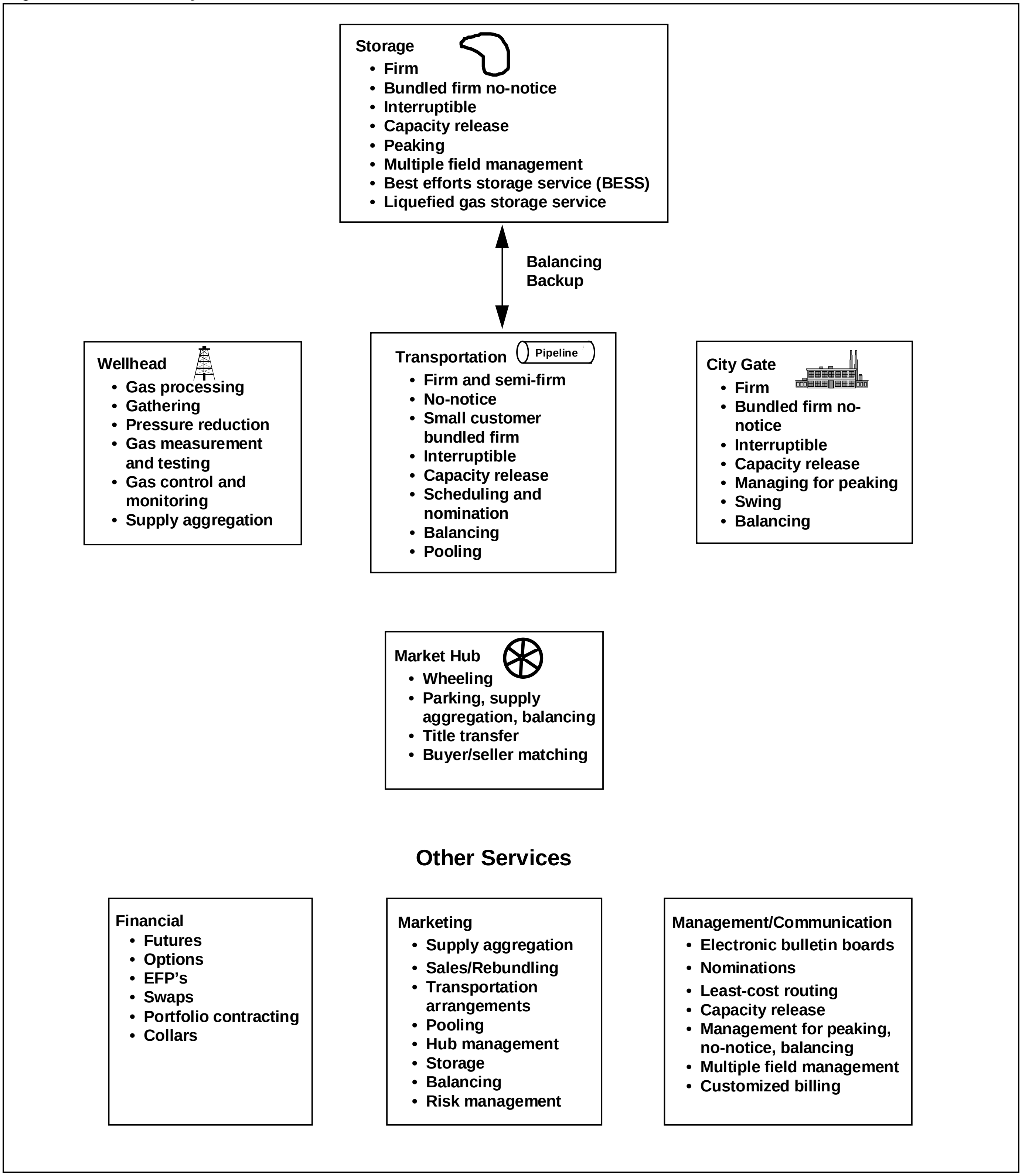
This chapter discusses how gas industry operations have changed as a result of Order 636. Particular emphasis is given to the increased array of services associated with gas supply and delivery, the creation of the secondary market in pipeline capacity, new methods for pipeline operational control, and the implications of changes in pipeline rate design.

New Services, New Corporate Structures

The separation of pipeline company services is a central mandate of Order 636. Pipeline companies can still make sales at market-negotiated prices and terms, but transportation service is now their primary function. However, other services, such as gathering and providing storage, may also be included in a pipeline company's menu of services. Customers now need services that were previously included in the pipeline company's gas sales service, such as meeting swings in gas supply requirements and storage. In addition, more gas services are being offered by natural gas companies than ever before (Figure 15). Companies representing all segments of the industry have capitalized on the procompetitive aspects of Order 636, such as unbundling, nondiscriminatory access to capacity, and mandatory changes in the accessibility of electronic information (although some participants in the gas industry remain skeptical about how pro-competitive some aspects of regulatory-driven changes are). Many firms, both regulated and unregulated, are offering these services—pipeline companies, marketers, and others—so that pipeline companies are facing increasing competition in many of their business areas.

During the restructuring process in 1992 and 1993, Order 636 guidelines were followed to set up specific services related to moving gas from the wellhead to the burnertip.

Figure 15. Diversity of Natural Gas Services



Gathering. Order 636 requires gathering services to be provided and priced separately from transportation services. In May 1994, FERC determined that it generally does not have jurisdiction over interstate pipeline companies' gathering affiliates because they are not considered natural gas companies under the Natural Gas Act (NGA). However, FERC jurisdiction could be invoked if a pipeline company abuses its relationship with its affiliate, such as giving transportation discounts only to those shippers using the affiliate's gathering service (see Appendix A). The gathering activities of other companies are not federally regulated.

Transportation. Order 636 requires pipeline companies to separate their sales activities from their transportation services. It automatically provides for the conversion of firm sales contracts for a like quantity of firm transportation capacity and sales. The firm transportation rights can be released under capacity release programs. Pipeline companies can also offer interruptible service. Several other types of transportation services are being offered as a result of Order 636.

Sales and Marketing. Pipeline companies choosing to continue their merchant service have for the most part created separate and distinct production and marketing affiliates. Order 636 requires that these affiliates not receive preferential treatment from their pipeline. Rather, the pipeline company is required to provide equal transportation access to all shippers. During 1993, several companies restructured their organizations as a result of this requirement. In most cases, the traditional merchant/transportation pipeline companies are subsidiaries of much larger parent corporations. In such cases, many pipeline companies have transferred their unbundled services (sales, gathering and/or balancing) to another corporate entity.

Small Customers. Because many small customers may not initially have the resources required to arrange for their own gas supplies, FERC has allowed a 1-year exemption period before they have to switch to unbundled service.[1] Within this period, pipeline companies must offer bundled service to those customers that elect to purchase gas from the pipeline company at rates that are cost-based.

No-Notice Service. Order 636 requires pipeline companies to offer their former sales customers a new service called "no-notice" to accommodate unexpected increases in customers' gas needs (see box, p. 40). This service provides firm transportation, firm storage, or a combination of the two up to a specified maximum daily quantity (MDQ). A shipper without no-notice service may be penalized for taking unscheduled quantities of gas. In contrast, a shipper with no-notice service may take unscheduled gas up to the MDQ without penalty.

Balancing. A key concern to pipeline operators is that shippers offset (or balance) their gas deliveries from the pipeline with injections of gas supplies into the pipeline on a monthly basis. If shippers withdraw more gas than they inject, pipeline pressure could fall too low to sustain deliverability. Conversely, if shippers inject more than they withdraw, pipeline pressure could rise to dangerously high levels. Because balancing is such an important issue, Order 636 allows pipeline companies to penalize shippers heavily if they exceed agreed upon tolerance levels. Many pipeline companies (as well as third parties such as marketing firms) offer balancing services, which help shippers avoid penalties. These services include additional tolerance levels, operational balancing agreements (OBA's), and other measures designed to let customers offset each others' imbalances.

Storage. Order 636 requires interstate pipeline companies to unbundle storage and transportation services. FERC has determined that pipeline companies only need downstream storage capacity for no-notice service and for operational maintenance such as load balancing. Storage capacity in excess of these amounts was allocated first to former sales customers if needed to maintain their maximum daily service entitlement. After converting customers selected their storage levels, all remaining storage capacity was offered to shippers on a nondiscriminatory basis. Pipeline companies are offering storage services on both a firm and an interruptible basis. (Chapter 4 examines in detail the potential effects of Order 636 on the storage segment of the natural gas industry.)

Corporate Restructuring Geared Toward Providing New Services

To provide gas services in the unbundled market, many pipeline companies have reorganized their corporate structures. These companies have adopted different strategies to do this (Table 2). For instance, under its Gas Services affiliate, Enron offers a fully integrated set of services such as supply, risk management, storage, balancing, and transportation. Other pipeline companies have spun off affiliates that provide a single service, such as storage or gathering. K N Energy's gathering and processing facilities, for example, have been reorganized into K N Gas Gathering, Inc., which is a wholly owned subsidiary of K N Energy. Additionally, parent corporations with multiple transmission subsidiaries, such as Coastal Corporation, have established a single affiliate to market gas services for their entire system.

[1] Small customers are defined in FERC Order 636-A as customers whose peak-day capacity needs do not exceed 10,000 thousand cubic feet per day. Federal Energy Regulatory Commission Issuance Posting System, Order 636-A, p. 58.

What Is No-Notice Service?

No-notice service is a major new service under Order 636. It is essentially a deluxe firm transportation (FT) service that was created to mimic the quality of service formerly available as part of sales service. Unlike sales service, however, no-notice customers must purchase their own, unbundled gas supplies. The main difference between no-notice and FT service is that under FT, if a shipper takes an amount of gas that exceeds scheduling limits negotiated with the pipeline company, then the shipper may incur penalties. Under no-notice, the shipper may exceed these scheduling limits without incurring daily scheduling penalties. To provide the service, a pipeline company may use pipeline-owned storage, borrow gas from contract storage, or allow gas scheduled for interruptible customers to be delivered to firm customers.

There are different types of no-notice service. Some pipeline companies levy a single reservation fee for a bundled package of storage and transportation service. On pipeline systems, such as Florida Gas Transmission, that lack access to storage, no-notice service only includes transportation.

Major differences between no-notice service and firm transportation are described below.

No-Notice Service	Firm Transportation
Firm service	Firm service
Storage capacity owned by the shipper and may be an integral part of the service	Service may include some small amount of pipeline-owned storage capacity for system balancing and load management
Lets shipper take delivery on demand up to its firm entitlement without incurring daily scheduling penalties	Shipper must have scheduled gas deliveries in advance (24 hours or more) and must balance receipt and delivery volumes or daily scheduling penalties will be assessed
Most likely sold at a higher price than FT to reflect the additional costs (i.e., for storage) incurred to support this service	
Replaces what formerly was sales service except that gas must be purchased separately	Similar to FT prior to Order 636 except that transportation and storage services must be unbundled.

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

Motivations for pipeline companies to form these affiliates include:

- Earning market-based returns on unregulated services
- Retaining those customers who still prefer one-stop shopping by rebundling services
- Differentiating their services to meet heightened competition from producers, independent gas marketers, and even LDC's (for transportation services)
- Increasing capacity utilization (raising system load factor) and system efficiency by expanding the market for gas services.

Managing and Operating the New System

The increase in shipper options poses some technical and operational challenges to both pipeline companies and shippers in maintaining reliable service. The basic requirement for a pipeline company is to keep enough gas in the line at all times to maintain the flow of gas. The operational integrity of a pipeline system may be threatened when gas is unexpectedly injected or withdrawn from the pipeline. A new set of rules has been devised to ensure that system integrity will be maintained. Two methods of system maintenance control have been implemented: flow control and monetary penalties.

Table 2. Corporate Restructuring in the Post-636 Market

Company	Post Order 636 Restructuring
Arkla, Inc.	**Arkla** is primarily a transmission and distribution company. Primary pipeline subsidiaries include: **Arkla Energy Resources** (AER) and **Mississippi River Transmission** (MRT). In 1993, AER became a separate wholly owned subsidiary of Arkla and Arkla 's gathering operations became a separate profit center. **Arkla Energy Marketing** (AEM), is the primary nonregulated marketing arm of the organization. AEM is expected to play an increasingly important role in building long-term markets for gas behind AER's pipeline system. AEM offers many of the traditional "merchant" services (i.e., supply arrangements) as well as transportation services.
Coastal Corporation	**Coastal Corporation** has subsidiaries in the following areas: natural gas transmission, marketing, refining, exploration and production, coal, and power. Primary pipeline subsidiaries include: **ANR Pipeline Company**, **Colorado Interstate Gas Company** (CIG), and **Wyoming Interstate Company, Ltd**. **Coastal Gas Services Company** (CGS), formed in 1993 to consolidate **Coastal's** unregulated natural gas businesses, provides natural gas gathering and processing services, manages price risks for **Coastal's** oil and gas operations, and operates producer financing activities. **Coastal** subsidiaries are expanding their investment in natural gas storage in response to increased opportunity in this area.
Consolidated Natural Gas Company	**Consolidated Natural Gas Company** (CNG) is a fully integrated transmission, distribution, exploration, production, and marketing company. In response to Order 636, CNG formed a marketing affiliate called **CNG Gas Services Corporation** to provide natural gas sales, transportation, storage, and other services to customers who prefer not to arrange supply and transportation transactions. **CNG Transmission Corporation** serves as the system's interstate gas transmission subsidiary which works with customers to develop restructured services. CNG "rents" capacity on its underground storage network (the Nation's largest underground storage system) directly to its customers. CNG intends to establish a market center on the **CNG Transmission** system at the Texaco Sabine Center, which serves Northeast markets.
Enron Corporation	**Enron Corporation** is a fully integrated exploration and production, transmission, distribution, and marketing company. Primary pipeline subsidiaries include: **Northern Natural Gas Company**, **Northern Border Pipeline Company**, and **Transwestern Pipeline Company**. **Enron Gas Services** is an unregulated subsidiary which in part provides local distribution companies (LDC's) and other customers with gas supply contract information and producers with long-term contracting opportunities. The other sectors of **Enron Gas Services** include: gas (physical delivery services and financial risk management), finance (provides capital to natural gas industry participants), liquids (gas processing and clean fuels businesses), and power (supplies gas and related services to the power generation industry) .
K N Energy, Inc.	**K N Energy** is a transmission, distribution, production, and marketing company, with substantial gathering, storage, and processing facilities. It recently reorganized its corporate structure to offer unbundled service opportunities. K N restructured its interstate transmission pipeline as a separate subsidiary business unit, **K N Interstate Gas Transmission Company**. Gathering and processing facilities, previously regulated by FERC, were reorganized into **K N Gas Gathering, Inc**., a wholly owned subsidiary. **K N** expanded its role in nonregulated natural gas-related business activities to include: gathering, marketing, and development of reserves.
Panhandle Eastern Corporation	**Panhandle Eastern Corporation** is the parent corporation of several subsidiaries that provide predominately natural gas transportation and related services. These pipeline subsidiaries include: **Algonquin Gas Transmission Company**, **Panhandle Eastern Pipe Line Company** (PEPL), **Texas Eastern Transmission Corporation** (TETCO), and **Trunkline Gas Company**. While transportation services will continue to be the main source of business for Panhandle, new services will provide important areas for growth. For example, PEPL will offer new market and field area flexible storage service that features customer-specific withdrawal levels. PEPL has filed a request to transfer the gathering assets from the western region of their system to a new, nonregulated affiliate. In 1993, Panhandle formed the marketing company **1 Source Corporation** to oversee many of the new transport-related services for all of its interstate pipelines. For example, Flex-X, a service provided by 1 Source Corporation, enables customers to tailor nominations through incremental expansion programs.
Transco Energy Company	**Transco** is primarily a transmission company with expanding interests in energy-related businesses. Pipeline subsidiaries include: **Texas Gas Transmission Corporation** (TGT) and **Transcontinental Gas Pipe Line Corporation** (TGPL). Although the company intends to remain primarily a transmission company, efforts are under way to develop other pipeline-related services to meet customer demand. In response to Order 636, **Transco Gas Marketing Company** (TGMC) was formed to provide gas marketing services to current and potential customers. TGMC manages all gas marketing operations, including the certified gas sales currently made by TGPL and TGT.
The Williams Companies, Inc.	**The Williams Companies** is primarily a transmission company with subsidiary interests in gathering, processing, and telecommunications. The pipeline company subsidiaries include: **Kern River Pipeline** and **Northwest Pipeline**. Gathering and processing services for William's pipeline subsidiaries are now offered through **Williams Field Services**. Supplementing its gathering activities, **Williams Field Services** has also developed a hub which allows producers to reach customers on multiple pipelines. In 1993, Williams created **Williams Energy Ventures**. This new company offers price risk management services and other information services such as electronic brokering of short-term capacity.

Note: Only wholly owned pipeline company subsidiaries are included in the table.
Source: 1993 annual reports for each company.

Controlling the Flow of Gas

Important considerations for a pipeline company are (1) that shippers take or inject no unscheduled amounts of gas,[2] and (2) that shippers' injections of gas into the pipeline are matched (over a certain period of time) by withdrawals of the gas from the system. For the most part, pipeline companies have been able to adapt some existing flow control methods–operational balancing agreements and curtailment– and have supplemented these with new methods, such as operational flow orders, to maintain the physical flow of gas through the pipeline. However, customers who fail to fulfill their responsibilities as shippers may be subject to monetary penalties, as described below.

Operational Balance Agreements (OBA) are contracts between pipeline companies and shippers or suppliers that have interconnecting facilities. Under an OBA, the imbalances of various shippers may be offset against each other. Any remaining system-wide imbalances will be settled by the operators of the interconnecting facilities. FERC had encouraged pipeline companies to institute OBA's as part of their restructuring filings. OBA's are an efficient means to maintain system integrity because they allow pipeline companies to settle imbalances with the operators of interconnecting pipelines or distribution companies rather than with each individual customer. Customers also benefit from OBA's; they do not need to be concerned about imbalance penalties, because imbalances are resolved by operators of the facilities.[3]

Operational Flow Orders (OFO) are emergency orders issued by the pipeline company that require a shipper to inject (or withdraw) gas into (from) the system at specific receipt (delivery) points to ensure the continued flow of gas through the pipeline. Several hours to a full day's notice must be given before a pipeline company can implement an OFO. This gives its shippers time to make necessary adjustments in their transportation arrangements. OFO's are meant to be issued only in emergency circumstances and are not to be used as a daily operational tool to manage gas flows.

Curtailment is the most severe of the control strategies pipeline companies use to ensure system integrity. Under curtailment, pipeline companies may cut off transportation or storage service to their shippers in the event of a major supply or capacity disruption. However, curtailments are not used for firm transportation absent *force majeure*. Each pipeline company spelled out a priority schedule for curtailment in its restructuring filing.

[2]Shippers that have no-notice service are exempt from these considerations, but may not exceed maximum daily quantities.

[3]Federal Energy Regulatory Commission, *Primer on Order 636* (April 19, 1993), pp. 86-87.

Monetary Penalties

Customers who fail to observe their agreed-upon schedules for gas takes, to maintain supply balance, or to respond to OFO's or curtailment orders may be assessed substantial monetary penalties (Table 3).

Penalties for violating curtailment orders or operational flow orders are usually set at relatively high levels, between $5 and $25 per million Btu, since such violations pose the greatest threat to pipeline operations.

Scheduling penalties can be imposed if a customer's actual receipts from the pipeline differ from its scheduled levels by more than 5 to 10 percent. These penalties are generally set at the interruptible (IT) rate, or about $0.25 per million Btu. More substantial penalties are applied when the unscheduled deliveries exceed the customer's contractual maximum daily quantity (MDQ) by more than a specified tolerance. For these "unauthorized overruns," penalties have been set at $5 to $25 per million Btu.

Imbalance penalties can be assessed when a customer's receipts of gas from the pipeline differ from its deliveries of gas into the pipeline. Generally, customers and pipeline companies have a specified period to resolve imbalances. If these are not resolved, then they are settled on a monetary basis ("cashed out") after the end of the month. During the cashout process, a customer who had taken more gas out of the pipeline during the month than it had injected may be charged an imbalance penalty in the form of a premium over the spot price of gas. Imbalance penalties usually follow a sliding scale, so that the larger the imbalance, the greater the premium over the spot price the customer must pay. If the customer overdelivered gas to the pipeline (i.e., injections exceeded takes during the month), the pipeline company will buy that gas from the customer at a discount from the spot price, with the discount increasing according to the size of the imbalance.

Cashout mechanisms are not intended to be sources of profit for the pipeline companies that use them. Rather, they are simply a device meant to enforce scheduling and balancing agreements between pipeline companies and their customers. To the extent that revenues from customers that have violated their scheduling agreement exceed the cost of operating the

Table 3. Characteristics of Monetary Penalties

Daily Penalties	Tolerance	Penalty	
Scheduling	10%	IT rate	
Overrun	3% - 5%	$5 - $25/MMBtu	
OFO or curtailment violation		$5 - $25/MMBtu	
Monthly Penalties		**Percent of Spot Price**	
Imbalance		Underage	Overage
0% - 5%		None	None
6% - 10%		110	90
11% - 15%		120	80
16% - 20%		130	70
21% - 25%		140	60
Over 25%		150	50

IT = Interruptible transportation. MMBtu = Million Btu. OFO = Operational flow order.
Source: Interstate Natural Gas Pipeline Association of America, "Interstate Pipeline Services for Customers After Restructuring," Report No. 93-5, December 1993.

cashout mechanism, pipeline companies must credit the excess to all customers.

Transportation Capacity Can Now Be Traded

The requirement that individual pipeline companies establish programs to let shippers "release" or resell their firm capacity rights is another cornerstone of Order 636.[4] A capacity release program permits a customer under any firm open-access rate schedule to release all or part of its capacity on a permanent or temporary basis. A replacement shipper may also re-release capacity if permitted by the terms of the initial release. This retrading of capacity effectively establishes a secondary market in pipeline capacity (see box, p. 44).

FERC required each pipeline company to administer the capacity release program for its system. Pipeline companies provide electronic bulletin boards (EBB's) where capacity offers are posted, bids are evaluated, and winning bids are determined (see box, p. 45). Releasing shippers may establish terms and conditions specific to their release, including the right to recall capacity under specified conditions (such as severe cold weather), a minimum acceptable price, indemnification, and creditworthiness requirements, and may also include provisions for determining the highest value or best bid. Nevertheless, it is the pipeline company as the administrator of capacity release who chooses among the bids based upon the posted terms and conditions. The releasing shipper and the acquiring shipper then execute a contract for the release of the capacity. The pipeline's own capacity must also be posted on its EBB, in direct competition with its customers' released capacity. The rates for released capacity may not exceed the maximum transportation rate specified in the corresponding FERC-approved rate schedule. In addition, shippers may not require more stringent credit conditions on replacement shippers than they have to meet themselves. Finally, pipeline companies must permit shippers flexibility in offering flexible receipt and delivery points to replacement shippers, to the extent permitted by the terms of the release (see box, p. 46).

The creation of a secondary market in pipeline capacity is intended to increase efficiency in the gas transportation industry. The secondary market helps establish market pricing for pipeline capacity. It reallocates unneeded capacity to shippers who value it the most. Pipeline companies benefit from the higher utilization of their systems and from the fact that releasing pipeline capacity can offset the need to build new facilities.

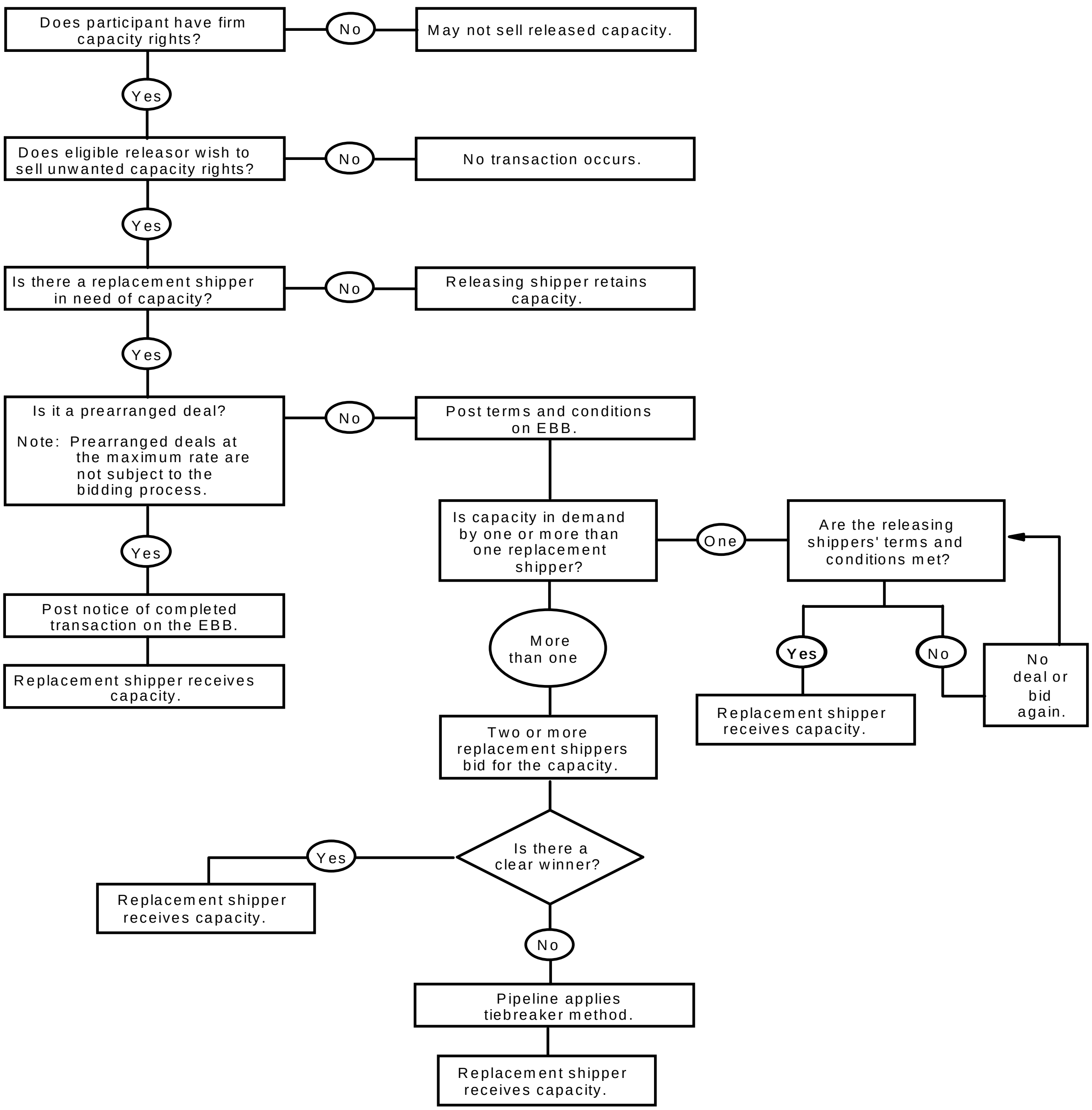
As currently constituted, however, some barriers to market pricing remain. One barrier is the price caps on both released capacity and the pipeline company's own interruptible transportation.[5] These price caps inhibit efficiency since they may prevent some customers from obtaining desired capacity

[4]Capacity release is the permanent or temporary resale of the rights to firm transportation and storage capacity on an open access pipeline.

[5]The maximum and minimum rates a pipeline company may charge for firm and interruptible service are spelled out in the rate schedules for each category of service. The maximum rates for firm service are also the price caps for released capacity.

Steps to Buying and Selling Released Capacity

The process of buying and selling released capacity may be very simple or quite complex. Several determinants of the complexity of this process are the number of competing shippers bidding for the capacity, the potential for a prearranged deal (an agreement by a shipper to release or sell firm capacity to a replacement shipper for 30 days or less at the maximum rate), the need for tiebreakers to ascertain winning bids, and the acceptance of contingent bids, etc. The process of buying and selling released capacity is outlined in the decision tree below.



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

Electronic Bulletin Boards

The exchange of electronic information has become a more critical part of daily operations in the natural gas industry. Like companies in the financial services, telecommunications, and news and entertainment industries, the financial success of companies in the gas industry increasingly depends on their ability to manage information and to harness information technology. A number of activities in the industry rely on electronic information, including buying and selling gas, trading capacity rights, tracking gas flows, billing customer accounts, and finding new gas fields. Indeed, some new services could not be provided without recent advances in using electronic information.

Most pipeline companies implemented some sort of electronic bulletin board (EBB) system in support of capacity release in 1993. These systems varied tremendously in their sophistication—some were quite basic, while others were developed on state-of-the-art computer networks using interactive menus. Growth in the secondary market for capacity during the 1993-94 heating season has led to increased use and familiarity with EBB's. The viability of a secondary market for pipeline capacity rights, however, will ultimately depend on the timely availability of key information on EBB systems. This information includes: minimum and maximum rates for firm services, capacity availabilities at different receipt and delivery points, contract listings, lists of pipeline company contacts, and other pipeline information.

While the efficiency gains from exchanging information via EBB's can potentially be very great, the EBB procedures have had some shortcomings. First, logging on to some of the EBB's can be time-consuming. Second, features on some of the EBB's (e.g., downloading information) have not been completed. Third, information on the different EBB's has not been standardized. Fourth, shippers that need information from multiple EBB's often have to learn how to use completely different systems.

A major step toward improving EBB's has been the development of a consensus on information standards. In July 1993, FERC approved a Notice of Proposed Rulemaking (NOPR) on EBB's. FERC later issued Order 563 (December 23, 1993) and Order 563-A (April 26, 1994), detailing what standardized capacity-related information pipeline companies have to provide their shippers and how the information can be downloaded. All pipeline companies were required to develop standardized data sets that include information such as offers to sell firm capacity, bids for firm capacity, awards for capacity, withdrawals of offers and bids, operationally available capacity, and systemwide notices. The deadline for implementation of Order 563-A was June 1, 1994 (for some companies this deadline has been postponed), although the adoption of common capacity codes is not required until November 1, 1994. In addition to FERC actions, a Gas Industry Standards Board (GISB), representing all segments of the industry, was formed in 1993 to facilitate the adoption of common protocols. In March 1994, a GISB working group agreed on an electronic data interchange format for gas transportation nominations and related transactions.

New applications of electronic information for the natural gas industry are constantly being developed. In response to some of the problems with the current EBB arrangements, some companies have begun developing "meta-systems" which could simultaneously process information from multiple EBB's. Third-party vendors are now offering new services such as least cost routing and portfolio optimization programs to help customers take advantage of the restructured marketplace for gas service.

even when they would be willing to pay more than the maximum allowed price.

A second potential barrier to market pricing stems from the competition between interruptible transportation and released capacity. Some concerns have been voiced regarding the ability of pipeline companies to administer a capacity release program efficiently in view of the fact that released capacity competes directly with the pipeline's own interruptible transportation.[6]

Experience with the market for released capacity during the 1993-94 winter has shown that capacity availability follows

[6]For examples, see Philip M. Marston, *Perestroika Revisited: The Empire Strikes Back* (September 1993); and Vincent Esposito and John Delroccili, "Gas Capacity Release: Opportunity or Pitfall?" *Public Utilities Fortnightly* (December 1, 1993).

Flexible Receipt and Delivery Points

Order 636 requires pipeline companies to administer flexible delivery points anywhere physical deliveries are possible on their systems. Customers who wish to change receipt or delivery points can do so without negotiating a new transportation contract. This obviously complicates the control of pipeline operations, but provides a great deal of flexibility to shippers.

More choices in where they inject and receive gas ensure that more buyers and sellers of both gas and capacity can conduct transactions. The flexibility also fosters a competitive secondary market for pipeline capacity. A shipper now has the opportunity to contract with more pipelines along a transportation corridor because of the ability to release capacity at pipeline interconnects along the corridor.

The benefits of increased flexibility were realized early in 1994, when suppliers were able to meet record gas demands as unusually cold weather swept over the eastern half of the country. The increased access to gas supplies and transportation made possible by Order 636 was widely cited as a key factor in getting gas to market during this critical period.

much the same pattern as the availability of interruptible transportation—during periods of peak demand, excess capacity is simply not available. For example, during the week ending January 17, 1994, when Arctic cold hit the eastern half of the United States, the amount of capacity released was only 0.3 billion cubic feet per week. Thus far, most released capacity has been sold at a discount.[7]

Transportation Rates Are Evolving

Order 636 has changed how transportation rates are determined. The requirement (with occasional exceptions) that pipeline companies adopt the straight fixed-variable (SFV) method of rate design for firm transportation customers has the potential to increase transportation costs for some customer classes, while lowering costs to others. In addition, the transition costs associated with restructuring under Order 636 will be passed through to all customers.

However, a number of measures may act to offset these cost shifts. One is the previously described capacity release provision, which enables customers to recoup some of their costs during periods when they do not need all of their contracted capacity. Other provisions include methods to mitigate impacts of SFV rate design on specific customer classes and mechanisms to credit firm customers with unexpected revenues from interruptible customers.

Most Companies Implement SFV Rate Design

SFV rate design requires that all pipeline fixed costs be recovered from firm customers through the monthly reservation fee and, to the extent that market conditions allow, from interruptible customers through the maximum rate for interruptible service. Variable costs are to be recovered through the usage fee applied on a volumetric basis to the gas actually transported.

The former modified fixed-variable (MFV) rate design had allocated some fixed costs to the commodity (usage) charge. Thus, the fundamental significance of the switch to SFV rate design is that firm customers pay for most fixed costs, and the pipeline company is assured of recovering most of these costs regardless of how much gas actually moves through the pipeline.

Most pipeline companies have implemented SFV for allocation and rate design purposes. There have been some exceptions to this trend, however. For example, Colorado Interstate Gas Company uses SFV for billing purposes but peak and annual demand for allocation purposes. Caprock Pipeline Company has been exempted because none of its customers pays reservation charges. Additionally, many pipeline companies have implemented SFV while also offering a one-part volumetric rate for small customers.

Because SFV shifts all firm fixed costs to the reservation fee, transportation rates have increased for many low load factor

[7]Pasha Publications Inc., *Gas Transportation Report,* Vol. 3, No. 3 (January 11-17, 1994), p. 1.

customers (those whose service needs are irregular, generally high in winter and low at other times), who have low overall levels of capacity usage over which to spread the cost impact. (See Appendix B for an example of how SFV rates for firm and interruptible transportation are determined on the basis of a pipeline's costs and operating characteristics.) Many high load factor customers, and particularly interruptible customers, have seen their rates decline. For example, a customer who needs 35 million cubic feet (MMcf) of daily service in the winter but only 10 MMcf per day in the summer has to reserve the full 35 MMcf per day year-round, even though much of this will be unused most of the year. In contrast, a customer whose gas use is more constant throughout the year will use most of its contracted capacity and will seldom be in a situation of paying reservation fees on unused capacity.[8]

Reducing the Burden of Shifting Costs

The cost shifting resulting from SFV rate design has been one of the most controversial aspects of restructuring the pipeline industry. In response, FERC developed a system of cost mitigation to redress concerns that pipeline restructuring would unfairly burden some smaller customers. In addition, other provisions of Order 636, including capacity release and a provision for crediting to firm customers any unexpected revenues from interruptible service, have the potential to reduce adverse cost impacts of restructuring.

Mitigating Cost Shifts

Pipeline companies were required to file cost mitigation plans if any of their customer groups, or even individual customers, would experience a 10-percent or greater change in revenue responsibility resulting from switching to SFV rate design.[9] Cost mitigation plans were to spread these cost shifts over a period of up to 4 years.

A review of the cost mitigation strategies of 13 major pipeline companies, representing 66 percent of natural gas throughput, reveals that many of these companies were not required to mitigate cost shifts (Table 4).[10] In these cases, FERC did not require mitigation because these companies did not have any customers that experienced more than a 10-percent increase in revenue responsibility.[11] If FERC did require cost mitigation, companies used one, or a combination, of the following specific mitigation measures described by FERC in Order 636.[12]

- **Seasonal rates.** Shippers may adjust their seasonal entitlements or their peak-day quantities, enabling them to lower their capacity reservations during off-peak seasons and to raise their capacity reservations during peak seasons.

- **Volumetric rates.** Transportation charges are based only on volume of gas delivered. No separate reservation fee is charged. This rate is generally restricted to small customers and allows them to avoid high monthly reservation fees for capacity they may not use. Using this technique, fewer revenues may be recovered from small class customers than from higher load factor customers.

- **Mixed rates.** A pipeline company may use MFV for cost allocation but SFV for establishing billing determinants.

- **Other procedures.** Shippers using a two-part or a bifurcated reservation charge pay for a portion of fixed costs through a monthly reservation fee. Shippers pay for the other portion of the reservation charge based on throughput. If they do not need as much capacity in a month because of changes in weather, they do not have to pay for a portion of their reservation charge.

Crediting Interruptible Revenues

The ratesetting process for interruptible transportation was not directly changed by Order 636. However, many aspects of Order 636 have had an indirect effect on interruptible transportation rates. In particular, the establishment of a secondary market in released capacity has introduced a new element of competition between released capacity and the pipeline company's interruptible transportation service. In this newly competitive environment, it is particularly difficult to project interruptible throughput for purposes of ratemaking. The interruptible revenue crediting mechanism is an interim measure designed to permit pipeline companies to make conservative estimates of interruptible volumes until

[8]See Energy Information Administration, *Natural Gas 1992: Issues and Trends*, DOE/EIA-0560(92) (Washington, DC, March 1993), Chapter 4, for a detailed discussion of the impact of SFV rates on pipeline company customers.

[9]This 10 percent does not include increases in rates from pipeline recovery of transition costs.

[10]Based on Total Deliveries reported in Table 28 of the Energy Information Administration, *Statistics of the Interstate Natural Gas Pipeline Companies, 1991*, DOE/EIA-0145(91) (Washington, DC, December 1992). This is the most recent publication of the report.

[11]Some pipeline companies proactively reduced changes in revenue responsibility (i.e., cost shifts) for some of their customers when submitting their restructuring filings to FERC. As a result, FERC did not require these companies to implement additional mitigation measures.

[12]Energy Information Administration, *Natural Gas 1992: Issues and Trends*, Chapter 4.

Table 4. Selected Pipeline Company Post-636 Transportation Rates and Costs

Pipeline Company	Rate Design		Mitigation Plans	Transition Costs	
	Before 636	After 636		FERC Estimate	Filed (as of 5/17/94)
Arkla, Inc.	EFV with a one-part demand charge	SFV	Implemented seasonal entitlements and volumetric rates to limit cost increases to 8 percent or less.	30,100,000	0
Columbia Gas Transmission	SFV	SFV	None required.	256,000,000	153,579,127
Columbia Gulf Transmission	SFV	SFV	None required.	9,000,000	0
El Paso Natural Gas	MFV with a one-part charge	SFV	None required. However they proactively instituted a one-part volumetric charge for small class customers. Field costs will be phased out of mainline rates over 5 years.	61,300,000	56,684,619
Koch Gateway (United Pipeline)	MFV with a one-part demand charge	SFV	Implemented a combination of seasonal entitlements and a 4-year phase-in of costs.	41,900,000	0
Natural Gas Pipeline of America	MFV with a one-part demand charge	SFV	Shifted revenue responsibility among different customers.	565,000,000	101,030,648
Northern Natural Gas	MFV with a one-part demand charge	SFV	None required.	78,000,000	203,436,097
Panhandle Eastern Pipe Line	SFV	SFV	None required.	70,000,000	27,810,850
Southern Natural Gas	SFV	SFV	Implemented a combination of seasonal entitlements and one-part volumetric rates for small customers.	0	133,217,857
Tennessee Gas Pipeline	EFV	SFV	Mitigation was required for only two customers. These customers received a reduction in their filed rates.	745,600,000	291,761,182
Texas Eastern Transmission	MFV with a one-part demand charge	SFV	None required. However, TETCO agreed to phase in higher costs for one of its customers over 7 years.	643,883,975	207,635,450
Texas Gas Transmission	MFV with a two-part demand charge	SFV	Implemented seasonal entitlements, reassigned demand charges among different customers, and offered one-part volumetric rates for small customers.	185,000,000	24,598,030
Transcontinental Gas Pipe Line	MFV with a one-part demand charge	SFV	None required. However, within the restructuring plan one customer was offered lower rates through seasonal entitlements.	10,000,000	1,841,228
Total				2,695,783,975	1,201,595,088

EFV = Enhanced fixed variable. SFV = Straight fixed variable. MFV = Modified fixed variable.

Note: EFV is a hybrid of the MFV and SFV rate design methodologies. The return on equity and related taxes are recovered as part of the usage fee under MFV and as part of the reservation fee under SFV. In contrast, under EFV rate design, 25 to 50 percent of the return on equity and related taxes are recovered as part of the usage fee, while the remainder is recovered as part of the reservation fee. As of May 17, 1994, $1.6 in total transition costs had been filed.

Source: Energy Information Administration, Office of Oil and Gas, based on conversations with rate and regulatory analysts at pipeline companies and the Federal Energy Regulatory Commission, Office of Pipeline Regulation.

actual experience with capacity release provides a basis for more accurate projections. This mechanism has the potential additional effect of reducing the cost burden of firm customers.

Rates for firm and interruptible services depend on the pipeline company's projection of both firm and interruptible throughput. If pipeline companies overestimate interruptible throughput volumes, they will not recover all of the fixed costs allocated to interruptible customers. If they underestimate interruptible volumes, however, they may recover more than their total fixed costs, earning more than the costs allocated to this service. If other projected throughput for firm transportation was correct, the pipeline company would overrecover its costs. This, coupled with a possible lengthening of time between rate case cycles, gives pipeline companies an incentive to underestimate future interruptible throughput.

Neither FERC nor the pipeline companies knew what the level of interruptible service would be in the post-restructuring environment. FERC developed credit mechanisms to offset the possible overrecovery of costs if interruptible throughput exceeds projections. Any additional revenue received as a result of higher-than-projected interruptible throughput is shared between the pipeline company and its firm customers. This procedure basically reduces reservation fees for firm service in response to overrecovery of costs through interruptible service. If pipeline companies exceed their projection of interruptible throughput, they must credit 90 percent of incremental revenues, after covering their variable costs, to firm customers. Pipeline companies keep the remaining 10 percent as profit. Thus, the credit mechanism gives pipeline companies an incentive to market their excess capacity and also reduces the reservation fees paid by firm customers. (See Appendix B for a numerical example of how interruptible revenue crediting may reduce firm transportation rates.)

Using Capacity Release to Lower Costs

The capacity release mechanism can also be used by releasing shippers to reduce their per-unit transportation costs. Firm customers must reserve enough capacity to meet their peak daily needs. During off-peak periods, they may find themselves paying reservation charges on significant amounts of unused capacity. By reselling unneeded capacity (on a temporary basis) in the secondary market, shippers can recover some of their costs from replacement shippers, thereby reducing their effective transportation rates.

If shippers were able to release all of their unneeded capacity for the full reservation fee, they could reduce their effective transportation rate to the equivalent of the maximum interruptible rate (Appendix B). In fact, it is theoretically possible for the releasing shipper to earn profits on capacity release, if the releasing shipper has obtained a discounted rate for the capacity and is able to charge a replacement shipper the full rate. In practice so far, the reverse has generally been the case—released capacity has sold at a discount.[13]

Paying the Costs of Transition

While the cost shifts resulting from SFV rate design may be partly offset by cost mitigation procedures, interruptible revenue crediting, and revenues from capacity release, another provision of Order 636 will temporarily increase costs to all customers. Under Order 636, pipeline companies are allowed to recover all transition costs that have been "prudently incurred" as a result of restructuring. These costs include:

- **Gas supply realignment (GSR)** costs incurred in reforming contracts with gas producers
- **Unrecovered gas (Account 191) costs** remaining when the purchased gas adjustment mechanism was terminated
- **Stranded costs** for assets no longer needed in an unbundled environment
- **New facilities costs** for new assets required because of unbundling.

Most pipeline companies provided estimates of these transition costs in their compliance filings. As of the implementation of Order 636, estimates of these costs were about $4.8 billion, which according to FERC represent the pipeline companies' "worst case scenarios" (Figure 16).[14] By mid-May 1994, $1.6 billion in total transition costs had been filed at FERC.[15]

In order to recover these costs, companies must file under Section 4 of the Natural Gas Act, using the mechanisms prescribed in Order 636 (Table 5). However, transition costs are subject to rigorous eligibility and prudence standards before FERC will allow recovery. GSR cost filings, in particular, have been set for hearing to ensure a thorough and complete review. (See Appendix B for an example of the impact of transition costs on pipeline company rates.)

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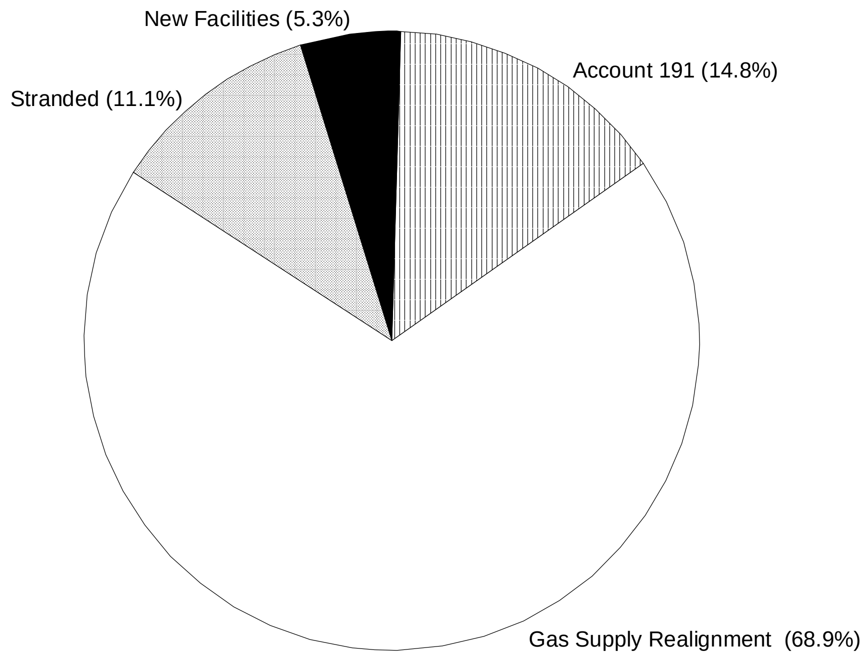
[13]Based on data published in *Gas Transportation Report,* Pasha Publications, Inc.

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

[15]Federal Energy Regulatory Commission, Office of Pipeline Regulation.

Figure 16. Estimated Transition Costs of the Pipeline Industry



Note: Total transition costs = $4.8 billion
Source: General Accounting Office, *Final Report on the Costs, Benefits, and Concerns Related to FERC's Order 636*, November 1993.

Gas Supply Realignment (GSR) Costs

Under Order 636, pipeline companies that previously offered bundled sales services had to reform the price and quantities of their gas supply portfolios to reflect their new role. They first could try assigning unneeded supply contracts directly to former sales customers. Then, any remaining contracts needed to be realigned to reflect market conditions. Of the costs incurred in reforming contracts, 90 percent are allocated to firm transportation customers; the remaining 10 percent of costs are allocated to interruptible transportation customers.

During the restructuring proceedings, FERC accepted certain specific methods to assign, reform, or maintain contracts that have been priced above current market conditions. In the case of contract assignment, pipeline companies could offer customers the option of a "reverse auction," where parties bid on how much the pipeline company would have to pay them to take over the above-market contracts. FERC allowed quarterly filings to recover GSR costs that actually had been incurred by the pipeline companies as a result of renegotiation. FERC allowed pipeline companies to collect a "GSR differential," which is the difference between the contract price and the higher of (1) an objective spot price index, or (2) the pipeline company's selling price of natural gas. Logically, the costs of above-market contracts will be partially offset by savings from below-market contracts in determining total GSR costs.

The costs of achieving this contract reformation have been compared to the take-or-pay dilemma of the 1980's when the market price for gas dropped below the prices that pipeline companies were committed to pay producers under existing contracts. As of June 30, 1992, pipeline companies had agreed to absorb about $3.6 billion of an estimated $10 billion in take-or-pay settlement costs. Of the remaining balance, pipeline companies have billed $3.5 billion directly and $2.8 billion on a volumetric basis.[16]

In contrast, most GSR costs, which FERC has estimated at $3.3 billion, will be passed through to customers. FERC, however, does not consider take-or-pay and GSR costs comparable, because GSR costs are the direct result of regulation and not the result of external conditions, such as the lower gas prices, increased supply of natural gas, and a deteriorating economic climate that precipitated the take-or-pay

[16]Federal Energy Regulatory Commission Issuance Posting System, Order 636-A, p. 343. **Direct billing** involves charging lump sums to customers based on past service levels. **Surcharges**, on the other hand, are increments to reservation and/or usage rates charged for present and future service.

Table 5. Cost Recovery Under the Natural Gas Act

Filing	Description	Recovery of Transition Costs	
Full Section 4	Now filed at the pipeline company's option in order to update rates to reflect major changes in pipeline revenue requirements. The revenue requirement is based on the company's capital structure, rate base, requested rates of return, and cost of service for a given test period. These filings also contain expert witness testimony to justify return and cost amounts. FERC examines the costs to ensure prudence and levels of return to ensure that they are just and reasonable. Intervenors often dispute the cost levels. Settlements occur when all issues of dispute are resolved, often without a hearing.	New facilities	New capital costs will be included in the companies' rate bases once the facilities become "used and useful."
		Stranded Costs	No longer needed facilities, other than upstream capacity, must be proposed for recovery in a Section 4 filing, and amortized over an agreed upon time period.
Limited Section 4	Limited cost changes, which are filed as one aspect of a full Section 4 filing rates. Avoids the lengthy and expensive process of filing a full Section 4 rate case each time costs change. Only specific costs are subject to challenge–not all of the costs of pipeline operation.	GSR	Recovered through a demand surcharge or negotiated exit fee. 90 percent of costs allocated to firm customers, 10 percent allocated to interruptible customers.
		Account 191	Direct billed to former sales customers in either a lump sum, over 12 months, or over some other reasonable period of time.
		Limited Stranded Costs	Account 858 costs (of providing upstream capacity to downstream customers) are recovered like Account 191 costs if the pipeline company had an Account 858 tracker prior to Order 636. Other Account 858 capacity costs are permitted to be surcharged over an agreed upon time period.
Section 5	Upon customer complaint or its own motion, FERC can order a decrease in rates if it determines that they are unreasonable. However, compensation to pipeline customers is not retroactive.	All	If customer complaints are justified, the future level of such costs can be reduced by FERC order. However, customers do not receive credit for costs they have already paid.

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

crisis of the mid-1980's. FERC contends that pipeline customers will benefit from this transition because they will no longer be required to pay above-market prices for gas.

Unrecovered Gas Costs

Because pipeline companies are making few, if any, gas sales under Order 636, the need for purchased gas adjustment (PGA) mechanisms has ended.[17] Pipeline companies have been left with unrecovered or overrecovered costs that were incurred for gas that has already been delivered to customers. These unrecovered costs are represented by the balance in Account 191. Since former bundled sales customers would have repaid or been refunded these costs in the past through the PGA

[17]In the past, pipeline companies offering bundled sales services used the deferred Account 191 to track the difference between the cost of gas paid by their customers and the pipeline companies' cost of purchasing gas from suppliers. These differences were passed along to customers through the use of PGA mechanisms. The PGA mechanisms allowed modification of customer rates through limited Section 4 filings, without requiring pipeline companies to submit full Section 4 rate case filings at FERC every time the cost of gas changed.

mechanism, pipeline companies will be able to direct-bill these customers based on the service levels of the prior 12 months, or other period if appropriate. This direct bill may be paid "...in either a lump sum, over 12 months, or over some other reasonable period of time, at the customer's option."[18] Some pipeline companies, however, reflected credit balances in Account 191 and have made refunds to customers.

Stranded Costs

A third type of cost relates to the pipeline companies' physical assets that were used to provide bundled sales service, but are no longer needed in an unbundled environment. For example, costs associated with storage, production, product extraction, transmission, or gathering facilities that will no longer be "used and useful" after restructuring may be recovered as stranded costs. Additionally, costs relating to upstream capacity that is not needed to maintain operational integrity or cannot be directly assigned to customers may also be recovered as stranded costs.[19]

A pipeline company's costs of providing upstream capacity to downstream customers have sometimes been tracked in a pipeline company's Account 858. FERC has allowed some pipeline companies to continue their Account 858 trackers and instructed others to implement new account trackers to recover stranded costs after Order 636. The balance remaining in Account 858 tracking mechanisms will be recovered through limited Section 4 filings.

Various customer groups have stated concerns that pipeline companies may be able to "...rid themselves of unused gathering facilities in declining areas, underutilized upstream capacity, and capitalized lease payments on properties held for future development" under the veil of stranded costs.[20] However, pipeline companies' claims for recovery of stranded costs will be examined by FERC for prudence.

New Facilities

The physical implementation of Order 636 also carries costs. For instance, metering, valves, and communications equipment are necessary to track gas flow more efficiently throughout a pipeline system. Also, the development of electronic bulletin boards (EBB's) and user-interface software is necessary to implement capacity release programs. The recovery of costs for new facilities will be treated as any other capital investments.

The Bottom Line: A Hypothetical Example

SFV rate design results in higher reservation fees for firm capacity than is the case with other rate structures. Therefore, the switch to SFV rates mandated under Order 636 has shifted costs to holders of firm capacity. In addition, transition costs will temporarily raise rates for all pipeline customers. These cost increases may be partly offset by revenues from released capacity and interruptible crediting.

The results of all of these interrelationships are summarized in a simplified example for a hypothetical pipeline (Table 6, the detailed calculations underlying these results are presented in Appendix B). Pipeline A is assumed to have total fixed costs of $900 million, variable costs of $20 million, and expected throughput of 1,200 trillion Btu (TBtu), of which 1,000 TBtu is expected to be firm service and 200 TBtu interruptible service. The system load factor (average daily demand divided by peak daily demand) is assumed to be 0.33, which gives a maximum total daily demand for firm service of 8.302 TBtu. The peak demand period lasts only 3 months. For the rest of the year, only 0.919 TBtu of firm daily capacity is required.

Given this cost structure and load factor, the monthly reservation fee for Pipeline A's firm customers is $8.47 per MMBtu. The maximum interruptible rate is $0.295 per MMBtu, and the minimum interruptible rate (which is also the usage fee for firm transportation) is $0.017 per MMBtu.

Transition Costs. Pipeline A is assumed to have transition costs including $90 million in GSR costs and $18 million in stranded costs amortized over 3 years. In addition, $10 million in new facilities investment is added to the rate base, increasing the monthly reservation fee by $0.019 per MMBtu to $8.49 per MMBtu plus a firm demand surcharge of $0.331 per MMBtu.

Interruptible Crediting. Pipeline A is assumed to sell twice as much interruptible throughput as anticipated (400 TBtu rather than the 200 TBtu projected). All the interruptible transportation is sold at a 50-percent discount from the maximum interruptible rate. Of the unexpected revenues, 90 percent are credited to firm customers, reducing the reservation fee by $0.23 per MMBtu. The reservation fee for firm gas transportation falls to $8.25 per MMBtu.

[18]Federal Energy Regulatory Commission Issuance Posting System, Order 636-A, p. 368.
[19]Federal Energy Regulatory Commission Issuance Posting System, Order 636, p. 198.
[20]Order 636-A, p. 397.

Table 6. Impact of Order 636 on Transportation Rates

Basic Assumptions	
Total System Fixed Costs (million dollars)	$900
Total System Variable Costs (million dollars)	$20
Firm Throughput (TBtu)	1,000
Interruptible Throughput (TBtu)	200
System Load Factor (average/peak)	0.33
Transportation Contract Term (months)	12
Peak Period (months)	3
Peak Period (days)	90
Off-Peak Period (months)	9
Off-Peak Period (days)	275
Total Throughput (TBtu)	1,200
Peak Firm Capacity Need (TBtu)	8.302
Off-Peak Firm Capacity Need (TBtu)	0.92
Total Gas Supply Realignment (GSR) Costs (million dollars)	$90
GSR Recovery Period (years)	3
Total Stranded Costs (million dollars)	$18
Stranded Cost Recovery Period (years)	3
New Facilities Investment (million dollars)	$10
SFV Rates	
Monthly Reservation Fee (Dollars/MMBtu)	$8.47
Usage Fee (Dollars/MMBtu)	$0.017
Maximum Interruptible Rate (Dollars/MMBtu)	$0.295
Minimum Interruptible Rate (Dollars/MMBtu)	$0.017
Transition Costs	
Firm Demand Surcharge from GSR and Stranded Costs (Dollars/MMBtu)	$0.331[a]
Increase in Monthly Reservation Fee from New Investment (Dollars/MMBtu)	$0.019
Effective Monthly Reservation Fee (Dollars/MMBtu)	$8.49[b]
Interruptible Revenue Crediting at 50 Percent of Maximum IT Rate	
Decrease in Reservation Fee (Dollars/MMBtu)	$0.230
Effective Monthly Reservation Fee (Dollars/MMBtu)	$8.25[b]
Capacity Release at 50 Percent of Reservation Fee	
Effective Decrease in Reservation Fee (Dollars/MMBtu)	$2.82
Effective Monthly Reservation Fee (Dollars/MMBtu)	$5.44[b]

[a]Effective for the 3-year recovery period for GSR and Stranded Costs.
[b]Plus demand surcharge of $0.331/MMBtu effective for 3 years.
TBtu = Trillion British thermal units. MMBtu = Million Btu. IT = Interruptible transportation.
Note: See Appendix B for more detailed calculations.
Source: Energy Information Administration, Office of Oil and Gas.

Capacity Release. Finally, Pipeline A's firm customers are able to sell all their excess capacity on the secondary market at a 50-percent discount from the maximum firm transportation rate. This effectively reduces their reservation fee to $5.44 per MMBtu.

The Bottom Line. The net impact of all of these elements on firm transportation rates is to reduce the monthly reservation fee for firm transportation from $8.47 per MMBtu under full SFV rates to $5.44 plus a surcharge of $0.331 that will be eliminated after 3 years. The revised rate incorporates the effects of transition costs, interruptible revenue crediting, and capacity release. The capacity release mechanism has the greatest potential to reduce firm transportation costs for releasing shippers. While the example shown here is highly simplified and somewhat unrealistic (e.g., it is unlikely that all excess capacity would find replacement shippers in the off-peak season), there is nevertheless ample reason to expect transportation costs to be lower than their full SFV levels under the pressures of competition.

Outlook

Natural gas transportation restructuring in 1993 affected all segments of the natural gas industry, from the wellhead to the burnertip. End users now have equal access to transportation and storage capacity rights. Concerns about the reliability of service in the post-Order 636 era have been dealt with by introducing new services like no-notice and providing pipeline companies with a variety of operational management tools such as operational flow orders, operational balancing agreements, and monetary imbalance penalties.

The adoption of SFV rate design by most pipeline companies shifted the recovery of most fixed costs to firm customers. After previous uncertainty about what constituted a "significant" cost shift, FERC used a generic 10-percent test in evaluating the reasonableness of pipeline mitigation proposals.[21] While many pipeline companies had to implement strategies to reduce anticipated cost shifts to low load factor customers, a number of pipeline companies did not have to implement mitigation. As required under Order 636, pipeline companies used other approaches to reduce cost shifts on firm customers: one-part volumetric rates, seasonal rates, interruptible revenue crediting, capacity release, and a 10-percent recovery of transition costs from IT customers. In addition, EBB's have been implemented under Order 636 requirements with the main goal of electronically facilitating the secondary release market.

Looking ahead, a range of issues may affect the restructuring process set in motion in 1993. Several companies proposed market-based rates in 1993, starting a trend that will probably continue. Information provided on EBB systems at the start of the 1993-94 heating season will become more standardized and easier to access. Estimations of projected interruptible service levels are likely to improve as the market for capacity release becomes more established. Small class customers will have to develop gas procurement strategies next year when their sales service exemptions expire. The types of gas services offered will probably become even more diverse. In particular, there will be greater recognition of the special needs of the electricity generation market. This will spawn continued improvements in the development of real-time tracking systems to improve the reliability of transportation service. Market hubs, touted in the past as a conceptual way to promote further competition and efficiency in the gas industry, became reality in 1993. In fact, several downstream hubs were proposed in 1993, providing improved access to supply areas and new transportation routes. The increased flexibility of the restructured transportation network will help the industry respond to the more competitive marketplace.

[21]FERC has stated that interstate pipeline companies should use, "as a general guideline a cost increase of no greater than 10 percent in designing minimization plans." Foster Associates, Inc., "FERC's Recently Adopted No Greater than 10 Percent Guideline for 'Significant' Cost Shifts to Individual Customers is Outcome of Evolution of SFV-Induced Cost Shift Mitigation Policy Established in Order No. 636," *Foster Natural Gas Report*, No. 1921 (April 1, 1993), p. 16.

3. Natural Gas Contracting

Adjustments in natural gas contracting have been necessary during the past decade to correspond to the changes that developed in the industry under open access regulation. Most recently, as a result of Federal Energy Regulatory Commission (FERC) Order 636, pipeline companies now serve a very limited role as merchants for gas sales. Thus the responsibility for gas purchasing has shifted to end users and local distribution companies (LDC's). The fairly simple set of transactions required to move gas from the wellhead to the burnertip under bundled service has been replaced by a more complex set of options requiring greater specificity in contracting (see box, p. 56.)

The unbundling of pipeline company sales and transportation enables customers to see more clearly the costs of each service available and to make contracting decisions accordingly. However, significant additional administrative effort is needed to select an appropriate combination of supply and transportation service contracts. Overall, the changes have allowed gas users and distributors to design contracts that meet their specific service needs. For example, end users and LDC's now have the option to purchase gas at the wellhead or, as is increasingly common, at a pooling point.

However, these new opportunities have made natural gas contracting more complex. Supply and transportation contracts must now frequently be augmented with contracts for balancing and storage—services that the pipeline company often performed under bundled service. Many companies are also using financial markets in order to manage the price uncertainty associated with volatile wellhead prices. Thus, the end user or LDC purchasing natural gas in the market today must address a wide variety of issues, including supply security, price risk, and pipeline company operational issues, and must take steps to ensure adequate coverage in their contracts. Marketers are playing an increasing role in the rebundling of these services, and many customers have come to rely on marketers for any one or all of these services.

Two of the newest features of the natural gas industry, the financial contract market and capacity release programs, figure prominently in a customer's ability to manage costs. The financial market in natural gas developed in response to the price volatility brought on by the increasingly competitive wellhead market (Figure 17). Both sellers and purchasers are now faced with a level of price risk they had not experienced prior to the late 1980's, but which is common in the trading of other commodities.[22] The futures contract market in natural gas opened on the New York Mercantile Exchange in April 1990, and the related options market became available in October 1992. These and other financial instruments provide market participants the opportunity to manage risk associated with wellhead price volatility and to take advantage of changes in the market.

As with the natural gas financial market, FERC's Order 636 capacity release program opened a new field of contracting for market participants. A capacity release program enables a shipper who has reserved transportation capacity to release excess capacity to a replacement shipper. The revenue received from the replacement shipper can be used to offset some of the costs associated with reserving firm transportation.

As contracts are restructured to match the new marketplace, some common characteristics are developing:

- Supply contracts are being signed for much shorter terms. While 20-year contracts were common before open access, they have now become rare. Today, any contract for more than 18 months is considered long term. The shorter term of most contracts ensures that the contracts closely reflect changing market conditions.

- Pricing clauses are being tailored to ensure that the commodity price reflects or follows the current market value of the commodity. This is typically done by indexing the price to spot or futures market prices or to prices for alternative fuels.

- Capacity release contracts may provide a useful secondary market for pipeline capacity. While there is the potential to offset some costs associated with the reservation of firm service, releasing shippers may need to provide deep discounts to secondary shippers to sell the capacity during off-peak periods. Thus, the revenues associated with capacity release may not provide a significant payback to the releasing shipper.

- Many market segments are facing new risks, particularly with respect to supply reliability and price uncertainty, but numerous services are being offered to allow companies to manage those risks. Companies now must

[22]For further reading, see Energy Information Administration, "Contracting for Natural Gas Supplies," *Natural Gas Monthly,* DOE/EIA-0130(94/02) (Washington, DC, February 1994).

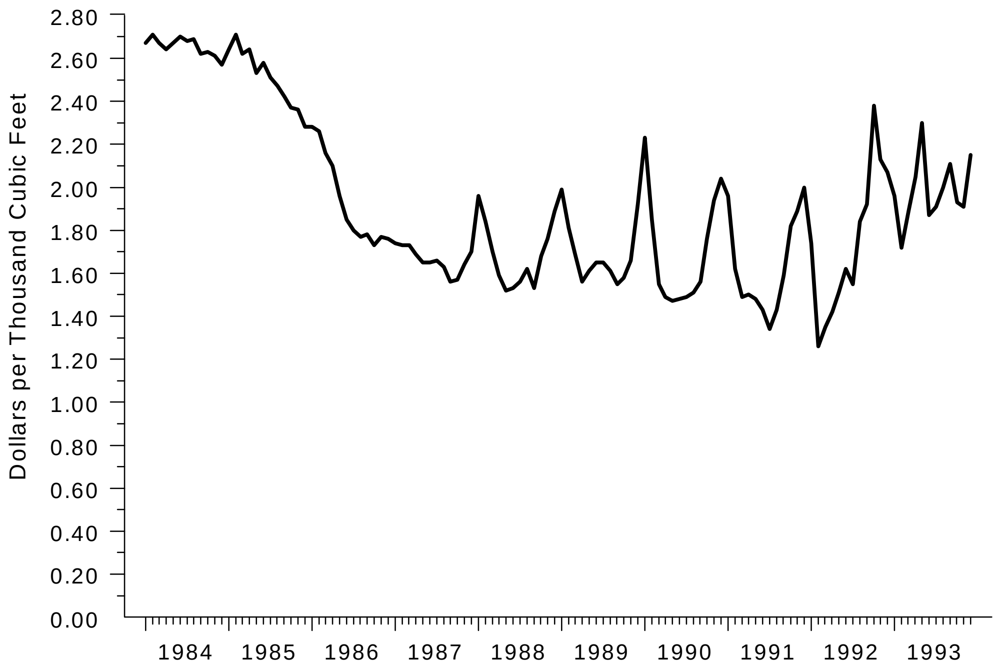
Characteristics of Natural Gas Contracting

Before Open Access[23]	After Order 636
At the Wellhead	**At the Wellhead**
Purchase contracts were between producers and pipeline companies.	Purchase contracts are between producers and: - End users - Local distribution companies (LDC's) - Marketers (who sell to end users and LDC's) - Pipeline companies
Prices were regulated by the Federal Energy Regulatory Commission.	Prices are market driven. Financial contracts are used to manage price risk.
Pipeline companies aggregated supply for customers.	Customers aggregate supplies or contract with producers or marketing companies for this service.
Pipeline companies were responsible for supply reliability.	Gas purchasers are responsible for supply reliability.
Downstream Customers	**Downstream Customers**
Firm customers obtained gas from the pipeline company through a bundled sales and transportation service.	Customers contract separately for gas purchases and transportation, receiving transportation from the pipeline company. Customers can purchase gas supplies from any seller, including a pipeline company. Many customers use marketing companies to rebundle services.
Transportation was typically along just one path and in many cases involved a single pipeline company. Interconnections between pipelines were used mainly for emergencies.	Customers determine the most economical combination of transportation route and location of gas purchase.
Operational adjustments to maintain system integrity were handled entirely by pipeline companies.	Customers are liable for penalties if they do not meet scheduled volumes, and match receipts and deliveries within tolerance. New services are available to avoid or reduce penalties.
Pipeline companies controlled most storage, using it to meet varying seasonal requirements and for operational control.	Customers are responsible for maintaining adequate storage to meet their peak-day requirements.
Pipeline companies offered interruptible service when capacity was not fully utilized. Revenues went to the pipeline company.	Firm shippers can release excess pipeline capacity and receive revenues to offset reservation costs. Trading takes place on electronic bulletin boards maintained by the pipeline companies.

[23]Federal Energy Regulatory Commission Order 436, issued in 1985, provided a mechanism whereby interstate pipeline companies could become "open access" transporters, thus separating their merchant and transportation functions. Pipeline companies accepting an Order 436 certificate agreed to make their transportation capacity accessible, or open, to any customer on a nondiscriminatory basis.

Sources: Energy Information Administration. **1984-1988**—*Historical Monthly Energy Review, 1973-1988.* **1989**—*Natural Gas Monthly*, March 1992. **1990—***Natural Gas Monthly*, March 1993. **1991**—*Natural Gas Monthly*, March 1994. **1992-1993**—*Natural Gas Monthly*, April 1994.

Figure 17. Average Natural Gas Wellhead Prices by Month, 1984-1993



carefully evaluate those risks in order to select the appropriate risk management strategy.

- Marketing companies are playing a key role in the restructured marketplace by offering the aggregation and bundling functions previously provided by pipeline companies. Customers can now see the costs of various services and contract only for those services they need.

- Commercial contracts, not regulatory guidelines, are now the tools being used by the pipeline companies to direct natural gas flows. Thus, all parties involved in contracting for natural gas supplies and transportation must understand and address pipeline operational concerns in their contracts.

- Flexibility is a key requirement in today's marketplace. A portfolio approach to gas contracting is one way of maintaining flexibility (e.g., using a combination of short-, mid-, and long-term contracts) while also addressing supply reliability and price stability issues.

This chapter discusses some of the complex contractual issues related to purchasing natural gas supplies and moving them along the interstate pipeline system from the wellhead to the end user. It describes how some of the new features of the market work and presents details and examples of how contracts may be structured in order to:

- Purchase natural gas and manage price and supply risk

- Transport natural gas and manage operational issues

- Combine various supply and transportation contracts with risk management tools to ensure that customer requirements are satisfied.

Contracts for natural gas storage services are only briefly discussed within the context of completing the services needed to meet customers' gas requirements. While these contracts have some specific terms to deal with the special requirements of moving gas in and out of storage during peak periods, storage facilities can be considered as an alternative supply source. In many respects, contracts for purchasing and moving gas into and out of storage are similar to those used to move gas from the production regions.

Terminology

Physical Contract. A traditional natural gas contract where delivery and receipt are expected. The term is used to distinguish such contracts from the newer financial gas contracts. The short-term (1- to 30-day) physical market is frequently referred to as the spot or cash market.

Financial Contract. A contract where the primary purpose is to manage price risk rather than to deliver or receive natural gas.

Futures Contract. A legal agreement between a party that opens a position on the futures market to buy or sell natural gas and the established commodity exchange (the New York Mercantile Exchange). In this agreement, the party agrees to accept or deliver, during a specified future month, a specified quantity of natural gas (10,000 million Btu per contract) meeting quality and delivery conditions prescribed by the exchange (for example, all deliveries take place at the Henry Hub in Louisiana). If delivery takes place, it occurs during the delivery month at a prescribed futures settlement price.

Swap. An agreement between two parties to exchange cash flows based on the difference between a fixed price and a market price and based on a specific quantity. The swap enables the party, in effect, to fix the price it receives or pays for natural gas. The quantity of gas in the swap is notional, or theoretical, because no exchange of gas ever takes place as a consequence of the swap itself. However, the notional value is set equal to the quantity of gas in the physical contract so that the price for all the gas covered in the physical contract becomes fixed by the swap.

Option. The right (but not the obligation) to sell or buy a futures contract at a certain price.

Hedge. A position in the financial market that is opposite to a position in the physical market. The expectation is that gains and losses from price movements will offset each other in the two markets when the position in the financial market is closed. For example, a producer who owns gas now and wants to sell it at some point in the future, would first obtain a futures contract to sell gas at that future time. When that time arrives, the producer sells the gas on the physical market and closes its position in the futures market with a contract to buy gas, thus completing the hedge. If the price of gas rose during this time, the producer would experience a gain in the physical market and a loss on the futures market. Similarly, if the price of gas fell, the producer would experience a loss on the physical market and a gain on the futures market.

Exchange of Futures for Physicals (EFP). Natural gas may be delivered directly through a futures contract at the recognized futures delivery point, the Henry Hub, at the futures contract price. However, in an EFP, delivery may take place at other than the Henry Hub and the actual delivered price may deviate from the futures contract price. An EFP may be negotiated at any time before the close of the market for a particular futures contract by two parties holding opposite positions on that contract.

Natural Gas Supply Contracts

Today, producers are free to sell their gas to any interested party, be it an end user, a local distribution company, or a marketer. Because some producers are also arranging for transportation, the first point of sale for natural gas may now take place anywhere from the wellhead to the burnertip. With the deregulation of wellhead prices, purchase contracts are now typical commercial agreements, no longer subject to regulatory conditions.

Contracts in the Physical Market

Contracts in the physical market for natural gas supplies have been greatly influenced by the development of a financial contracts market in natural gas (see box above). Both pricing provisions and the term (length) of the physical contract have been affected. Experience has shown that a multi-year, fixed-price contract is not appropriate for most situations in today's market. Average terms have been shortened significantly, and prices are now frequently indexed to a published spot price or the futures price. Such changes enable contracts to reflect market conditions as closely as possible throughout the term of the contract. It is useful for this discussion to divide supply contracts into three categories by term:

- Short-term contracts, where deliveries and receipts are arranged for 1 month or less

- Mid-term contracts, which extend out 18 months

- Long-term contracts, where deliveries and receipts are arranged for longer than 18 months.

These contracts vary in a number of ways. Short-term contracts are relatively simple contracts for a fixed volume of gas at a fixed price. Mid-term contracts are for either fixed or variable volumes, and most have provisions that allow prices to move higher or lower depending on market conditions. Long-term contracts are much more difficult to categorize, reflecting the specialized needs of customers for longer term commitments. One distinction, however, is that it is more difficult to use financial gas contracts to manage the price risk in long-term contracts primarily because the futures contract market only extends to 18 months.

Short-term Contracts

Today there is a very active short-term market for fixed-price, fixed-volume receipts and deliveries of gas, usually referred to as the spot or cash market. Contracts in this market are written for deliveries of gas for 30 days or less. Many of these contracts are finalized during a period at the end of the month called "bid week" (see box, p. 60). Other contracts are negotiated after bid week, during the actual delivery month. The size of this market varies greatly between months and depends on expectations about price movements during the delivery month.

The clauses in short-term contracts are very similar and can be generally characterized as:[24]

- Fixed price, where the price is the market price on the day the contract is completed

- Fixed volume, where the volume is set for a consistent flow of gas per day over a set period of time with little variation.

The short-term contract market serves several important needs. First, it allows end users to purchase gas to satisfy unexpected shifts in demand. Second, it allows short-term imbalances in supply to be corrected. Short-term contracts are particularly useful to customers with fuel-switching capabilities because they can acquire gas from the area where it is cheapest each month. In longer term, price-indexed contracts, they lose this flexibility because the contract is indexed to a particular price, which may not always be the lowest over time.

To facilitate the contracting process, companies often have already established creditworthiness with each other so that all that is needed is a signature on a standard contract form. In those instances where the client needs to establish creditworthiness, the process is still relatively simple. The seller may only require a partial prepayment or a minimal credit check because these contracts involve relatively small amounts of gas.

In the past several years, the total volume of gas covered by short-term contracts is believed to have decreased substantially.[25] Interestingly, this decline corresponds with the phenomenal growth in the futures and related financial markets. The shorter the term of the contract, the less likely a financial market is being used to mitigate price risk. In fact, parties expect so little price risk in these contracts that if the market price changes dramatically between the time a contract is negotiated and the time deliveries are to begin, parties have been known to "walk away" from contracts.

The futures contract market not only complements the conventional spot contract for gas but also competes with it. Actual receipt and delivery of natural gas can be arranged through the standard futures contract itself or through an Exchange of Futures for Physicals (EFP) transaction (Figure 18). In January 1994, deliveries arranged through EFP's were 131 trillion Btu, equivalent to 8 percent of dry gas production in that month. While deliveries arranged through EFP's greatly exceed those through standard futures contracts—in January 1994, EFP delivery arrangements were nearly 10 times those under futures contracts—both markets have shown strong growth. From January 1992 through January 1994, deliveries arranged through futures contracts quadrupled, while deliveries through EFP's increased nearly seven-fold.

Mid-term Contracts

Mid-term contracts cover gas deliveries up to 18 months, although most mid-term contracts are for 1 year or less. The 18-month maximum derives from the fact that the maximum trading period for a futures contract is 18 months. Thus this becomes the maximum practical term over which the futures

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[24]John Gregg, "Getting Your Mind Right! Gas Supply Contracting Without a Safety Net," *Public Utilities Fortnightly* (Washington, DC, October 1992), pp. 31-33; and Mike Rieke, "Natural Gas Contracts: Issues and Strategies," *Gas Daily* Conference (Houston, TX, November 4, 1993).

[25]Rick Hagar, "U.S. Producers Becoming Adept at Direct Sales of Gas to End Users," *Oil and Gas Journal* (July 10, 1989), pp. 17-19; and John C. Herbert, "New Features in Long-Term Contracts from Order 636," *Natural Gas* (New York: Executive Enterprises, Inc., April 1993), pp. 6-10.

Bid Week

"Bid week" occurs at the end of each month when deals are finalized for the sale and purchase of natural gas and nominations are made for transportation capacity on pipelines for the next delivery month.

Before open access transportation was widely available, pipeline companies made arrangements with producers and scheduled the capacity on their own systems every month in order to meet the demands of their firm sales customers. With the development of open access and the spot market, however, interruptible transportation became more readily available. For operational and scheduling purposes, the pipeline companies required interruptible shippers to notify them each month of the capacity they would require for the next delivery month. Each pipeline company set a date and time, or "nomination deadline," for this purpose.

Because shippers could not be sure that they could move the gas they wanted to purchase until the capacity arrangements had been completed, the final price for a cash sale was determined near to the time that arrangements for the capacity were finalized. Initially, capacity nomination deadlines for the various pipeline companies occurred over about a 10-day period near the end of the month, thus "bid week" became a time of nominating pipeline capacity and finalizing gas prices and quantities on the cash market. Bid week has been compressed as pipeline companies have shifted their deadlines so that they all fall within a few days of each other.

At first, nominations had to be mailed in, and the pipeline company would often phone the shipper to confirm how much capacity would be available. The speed of handling nominations has increased however, first with the use of faxes, and today with the use of electronic bulletin boards.

When the futures market in natural gas opened in April 1990, it added a new dimension to bid week. The final day of trading on a futures contract for a given delivery month has been 6 to 8 business days before the beginning of the delivery month. Today, almost all pipeline nomination deadlines fall on or after the close of the futures market. Some cash deals are made before the futures market closes, influencing the final price posted in this market. Similarly, when the futures price for a delivery month becomes final, this influences the final cash deals that are made before the last nomination deadline passes.

Bid week developed along with the growth in interruptible transportation, however, firm shippers are also required to make monthly nominations to their pipeline companies for the same operational and scheduling purposes.

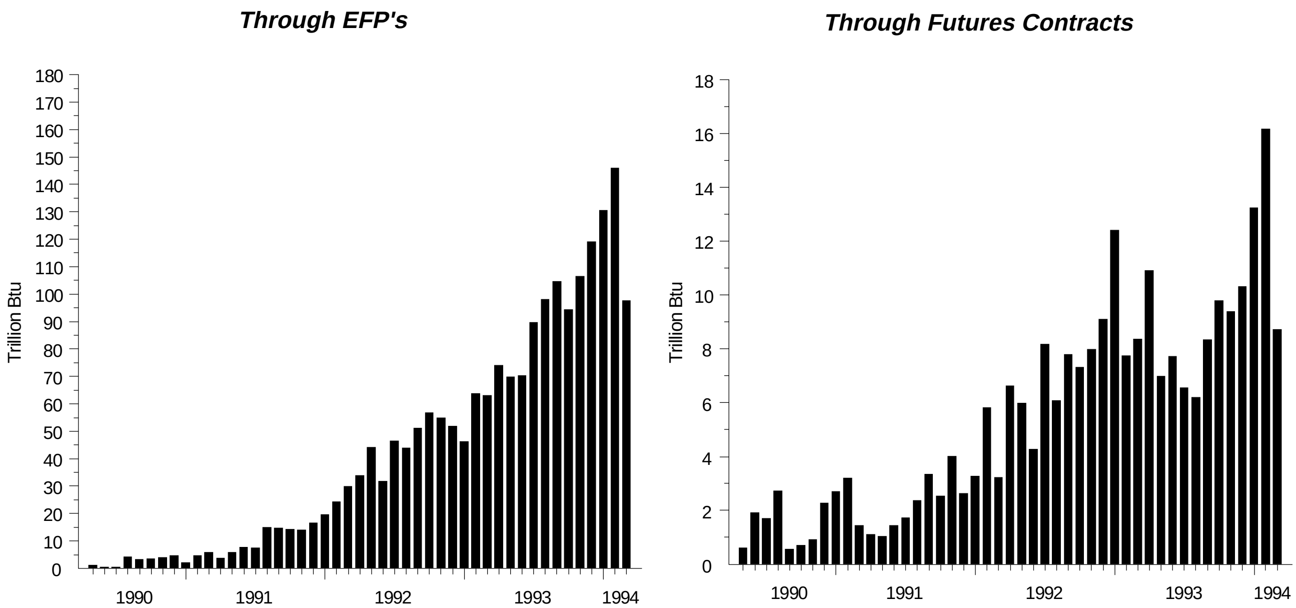
market can be used to provide price discovery and to manage price risk. Mid-term contracts can be characterized by:[26]

- Variable prices, where the cost of the commodity is indexed over time to the futures price or some published spot price
- Fixed reservation and service fees, where the purchaser must pay a set fee to reserve a specified amount of gas over time and service fees for any special services (such as variable daily or monthly deliveries) provided by the seller
- Mainly fixed volumes per day or per month with modest variation, although variable volumes are allowed under some contracts, such as "swing contracts."

The ability to hedge the price risk in mid-term contracts with a financial instrument is important because of the great volatility in gas prices during the past several years and because of the tendency for prices to be higher during the heating season than in the rest of the year. The natural gas futures contract markets for the heating season months have been very active; thus, these markets have been very liquid. Because mid-term contracts can extend over a heating season, they are operationally very important to large distribution companies in meeting the gas needs of their customers. Some

[26] Rick Hagar, "U.S. Producers Becoming Adept at Direct Sales of Gas to End Users," *Oil and Gas Journal* (July 10, 1989), pp. 17-19; Cleve T. Hogarth, "Value-Added Contracts Rather than Long or Short-Term," *Natural Gas* (September 1993), pp. 8-13; Richard Peterson, "LDC Purchasing Strategies in a Competitive Gas Market," *Utility Industries in Transition*, 25th Annual Conference, Institute of Public Utilities (Williamsburg, VA, December 13, 1993); and Carl V. Swanson, "The New Market System: Will it Work for LDCs?" *Natural Gas* (January 1993), pp. 6-8.

Figure 18. Delivery Arrangements for Natural Gas by Month, May 1990 - March 1994



EFP = Exchange of Futures for Physicals.
Note: One unit on the "Through EFP's" scale represents 10 times the volume of one unit on the "Through Futures Contracts" scale.
Source: Commodity Futures Trading Commission, Division of Economic Analysis.

swing mid-term contracts are also geared to serve seasonal demands. The amount of gas taken daily under a swing contract can vary as long as the customer takes a certain fixed quantity during some specified period, such as a year. The customer pays a special fee for this right.[27] Such variable-volume, mid-term contracts are often used by LDC's with a large percentage of residential and commercial customers who have highly variable demand that typically peaks during the winter.

Long-term Contracts

Contracts for more than 18 months may cover several heating seasons and are, therefore, operationally long term. Firms that enter into such contracts, which are inherently more risky, may have special needs that require a reliable, long-term commitment. For example, a producer may desire a long-term contract in order to cover certain fixed costs necessary to expand production capability. In such a case, a producer could enter into an agreement to supply gas at a set price to an industrial firm or group of industrial firms. In return, the industrial customer would agree to finance any new production facilities needed to produce the gas, thus enabling the producer to meet its commitment to the industrial customer.

Another example of using a long-term contract to support project finance would be a cogenerator that needs to have a relatively fixed fuel budget over several years in order to support investment in plant construction. A cogenerator usually obtains a long-term agreement for the sale of its power to an electric utility.[28] The project manager then seeks a fuel supply contract to guarantee a reliable supply at a relatively fixed price. Many lenders for the project require that the fuel contract cover the time required for full payment of the debt. Lenders also look for fuel-pricing terms that will enable the cogenerator's fuel costs to be consistent with the revenues to be received from the sale of electricity.

Long-term contracts usually are for a fixed quantity of gas delivered on a monthly basis. In contrast to the restrictive

[27] Michael T. Langston, "Case Study: Southern Union Going for Long-Term Contracts," *Natural Gas* (September 1993), pp. 19-22.

[28] C. Richard Baker, "Project Financing for Cogeneration," *Public Utilities Fortnightly* (March 15, 1990), pp. 26-34; Timothy Burn, "Clinton Medina wells pay off for Atlas Resources on long term gas contracts," *Northeast Oil and Gas World* (October 1993), pp. 9-11; and John S. Woodard, "Long-term Gas Supply Contracting: New Contracts More Flexible," *Natural Gas* (May 1993), pp. 2-7.

price provisions in the long-term contracts of a decade ago, prices today are more market responsive, often being indexed to the futures market or a published spot price. Some price terms may be renegotiated if the published price index no longer reflects the spot market. Otherwise, the price terms are not expected to be subject to renegotiation as long as active spot and futures markets exist.

Because long-term contracts extend beyond the 18-month price discovery period of the futures market, they usually have more special conditions or provisions than short- and mid-term contracts.[29] Some long-term contracts have a reservation fee that may be either fixed or variable.[30] This fee is to compensate the supplier for any additional costs incurred in arranging for supplies to be available over the long term. Other long-term supply contracts may have "take-or-release" clauses whereby the purchaser, such as a marketer, agrees to make every reasonable effort to buy a specified volume of gas from a supplier. Yet, the supplier has the right to cancel the contract or reduce the volume of gas available under the contract if the buyer does not take the stipulated amount. Such provisions, unlike take-or-pay clauses of the past, relieve the buyer from paying for untaken volumes. Nonetheless, a take-or-release clause could motivate a marketer to take gas from the supplier and sell it to another buyer, even a competing marketer, in order to maintain its relationship with the supplier. Selling to a competing marketer is not as strange as it might seem in the increasingly flexible gas industry. In fact, small producers sometimes need to purchase gas from large producers in order to satisfy their own current requirements under long-term contracts. These relationships are indicative of an important change in the gas industry. Specific supplies, even in long-term contracts, are less likely to be dedicated to a particular buyer today than in the past. Instead the market is constantly reallocating available supplies based on supply and demand conditions and the willingness of buyers to pay for gas.[31]

Price Risk Management

Volatile wellhead prices create risk for both the seller and purchaser of natural gas. A seller may see the value of its product decline if the sale is preceded by a drop in prices; if prices rise rapidly, a purchaser may find it has to pay a higher price than if it had been able to buy gas just 1 month earlier. The transformation of the natural gas wellhead market from one where prices were heavily regulated to one where gas is priced as a commodity led to the development of a financial contracts market in natural gas. These markets provide both price discovery for the physical market and a means of managing price risk for many market participants.

The futures contract market in natural gas opened on the New York Mercantile Exchange in April 1990, and the related options market became available in October 1992. Natural gas swaps contracts are also available, but, like some options, swaps are not traded on a regulated exchange. Both the futures and options market have become important features of the natural gas industry; however, some suggest that the size of the swaps market makes it much more significant. For example, during 1993, the swaps market accounted for 10 to 25 times the open interest in the futures contract market.[32]

Each financial instrument has its own unique appeal based on the specific requirement of the user. They vary according to effectiveness, ease of use, and cost (Table 7). Simple examples of how each of these financial tools may be used to manage price risk are shown in the box on pages 64 and 65.

In practice, market participants may use more than one instrument to manage their risk. For example, a company that purchases gas may engage in a swap in order to stabilize its effective purchase price; however in doing so, the company gives up the opportunity to benefit if gas prices drop. If, after entering the swaps market, management feels that the price of natural gas is going to drop, the company could buy an option to sell a futures contract (a put option). The company would want the price of gas in this option to be below the current market price. Then if prices do drop, falling below the gas price in the option, the option itself will have a greater value. The company should then be able to find a party willing to purchase this option at a higher price than the company had paid. Thus even though the company has a swap contract, it is able to experience a gain in income from the change in market prices by also participating in the options market.[33]

[29]John C. Herbert, "New Features in Long-Term Contracts from Order 636," *Natural Gas* (April 1993), pp. 6-10; and John S. Lowe, "Gas Contracting: The Lessons of the Seventies," *Natural Resources and Environment*, Vol. 3, No. 4 (Winter 1989), pp. 3-48.

[30]Elizabeth Olmsted Teisberg and Thomas J. Teisberg, "The Value of Commodity Purchase Contracts with Limited Price Risk," *The Energy Journal*, 12, 3 (1991), pp. 109-127.

[31]Cleve T. Hogarth, "Value-Added Contracts Rather than Long or Short-Term," *Natural Gas* (September 1993), pp. 8-13; John A. Gartman, "Natural Gas Purchasing Strategies of LDCs," NARUC Annual Regulatory Studies Program (East Lansing, MI, August 12, 1993); and John S. Woodard, "Long-term Gas Supply Contracting: New Contracts More Flexible," *Natural Gas* (May 1993), pp. 2-7.

[32]For further discussion, see "Separating supply from price," *Oil and Gas Investor*, Vol. 13 (June 1993), p. 47.

[33]"NYMEX Energy Options: Strategies at a Glance," brochure, New York Mercantile Exchange (1993).

Table 7. Features of Financial Instruments

Characteristics	Futures	Options	Swaps
Purpose	Fix price of gas for future sales and purchases	Fix price range for future sales and purchases	Fix price for future sales and purchases
Regulator	CFTC and NYMEX	CFTC and NYMEX. Unregulated also available	None
Term	Maximum 18 months	Maximum 12 months for regulated options. Unregulated options are frequently available for several years	Several years
Liquidity	Standard contract encourages broad industry participation in any one contract, which supports a liquid market	Standard contract encourages broad industry participation in any one contract, which supports a liquid market	Customized contracts limit participation in any one contract, which results in less liquidity
Costs	Margin[a] requirements result in variable costs. Extensive administrative costs	Fixed fee and minimal administrative costs. No margin requirements	Fixed, minimal administrative costs. No margin requirements
Credit Check	Minimal	None	Extensive
Delivery Capability	Yes	No	No
Performance	Guaranteed	Guaranteed if regulated, otherwise not	At risk

[a]The margin is a performance bond that typically ranges from 5 to 15 percent of the value of the futures contract.
CFTC = Commodity Futures Trading Commission. NYMEX = New York Mercantile Exchange.
Source: Energy Information Administration, Office of Oil and Gas.

Natural gas marketers have been the most active participants in the futures contract market—protecting the value of the gas they have already purchased and attempting to fix prices for future purchases (Figure 19). Marketers use futures contracts to hedge both purchases and sales of natural gas and may also use the futures market to arrange some swaps. Producers and end users have also engaged in the futures market. But many local distribution companies have been prevented from direct participation by their State regulatory agencies, primarily because procedures have not yet been approved for treating any gains and losses from futures market activities.

Supply Risk Management

Although price risk can be managed effectively through financial contracts, the risk that gas may not be shipped and received when needed cannot be covered through such contracts. Supply risk is usually addressed by placing specific clauses and conditions in contracts and, in addition, by an overall strategy of supply source diversification.

Contract Provisions

"Evergreen" clauses. Evergreen or rollover clauses extend the obligation of the seller and buyer to ship and receive gas, respectively, after the term of the contract has expired. Such clauses were suggested by FERC in Order 636. These clauses essentially provide the seller and buyer with a grace period to ensure that there is time to make adjustments at the end of a contract to avoid a disruption in supplies. These clauses also enable the parties to extend the term of the contract, presuming that the experience with the contract has been fair and equitable to both parties.

"Corporate guarantee" clauses. Some contracts have corporate guarantee clauses that obligate the parent of an affiliate to supply gas if the affiliate goes bankrupt or is

Financial Market Examples

This section shows how three major financial tools—futures, options, and swaps—are used in conjunction with activity in the physical market to manage the risk inherent in volatile wellhead prices. In general, using these tools involves foregoing some opportunities for profit or savings, in exchange for protection from adverse price moves. For simplification, it is assumed in these examples that the spot or cash price for natural gas is equal to the price in the futures contract for the month in question. Also, the examples present payments on a per-unit basis only. In the market, parties will actually obtain a sufficient number of financial contracts to cover the total volume of gas for which they want price protection. For example, if a party were concerned about hedging the price for 100,000 million Btu of gas, the party would obtain 10 futures contracts because each futures contract is for 10,000 million Btu.

Futures

Parties that prefer the security of a regulated market and that can meet the margin requirements (performance bond) would use the futures market to fix the price of gas. Fixing the price allows parties to limit losses on future sales or to stabilize the cost of future purchases. As an example of how the futures market can be used, consider a producer who sees a September futures market price of $2.00 per million Btu (MMBtu) and who would like to sell gas in the cash market in September at that price. In order to lock in the $2.00 selling price, the producer will enter the futures market now, obtaining a futures contract to sell gas in September at $2.00. When trading on the September futures contract closes, the producer must offset its position by obtaining a futures contract to buy gas at the September closing price.

If the closing futures price on the September contract and the spot price for September delivery are $2.00 per MMBtu, then the producer gets its desired price and there is no net gain or loss when closing the futures market position. If the price is not $2.00:

- **Case 1:** Spot and futures prices rise, for example to $2.15 per MMBtu
  - The producer sells gas on the cash market for $2.15 per MMBtu.
  - The producer sees a net loss of $0.15 per MMBtu when closing on the futures market by selling at $2.00 and buying at $2.15.
  - The effective net selling price is $2.15 - $0.15 = $2.00 per MMBtu.

- **Case 2:** Spot and futures prices fall, for example to $1.80 per MMBtu
  - The producer sells gas on the cash market for $1.80 per MMBtu.
  - The producer sees a net profit of $0.20 per MMBtu when closing on the futures market by selling at $2.00 and buying at $1.80.
  - The effective net selling price is $1.80 + $0.20 = $2.00 per MMBtu.

Options

If it is not important to fix the price but rather to limit risk within a range of prices, a party can enter the options market rather than dealing in the futures market directly. Parties may also use unregulated options to manage price risk if they want to purchase an option for a term not readily available on the regulated exchange. As an example of how an option can be used, consider a producer who pays $0.05 per million Btu (MMBtu) to buy an option for a futures contract to sell gas at $2.00 per MMBtu. Later, the producer will make a deal on the cash market at which time:

- **Case 1:** The spot and futures prices are higher than the price in the option, for example, $2.15 per MMBtu
  - The producer will not exercise its right to sell the futures contract at $2.00 because to close out its position on the futures market, it would have to acquire simultaneously a futures contract to buy gas at the current price of $2.15, thus losing $0.15 per MMBtu (gross).
  - The producer will sell gas at an effective net price of $2.15 - $0.05 = $2.10 per MMBtu.

- **Case 2:** The spot and futures prices are lower than the price in the option, for example, $1.80 per MMBtu
  - The producer will exercise its right to acquire the futures contract to sell gas at $2.00 and will immediately close its position by acquiring a futures contract to buy gas at the current price of $1.80, making a profit of $0.20 per MMBtu (gross).
  - The producer will sell gas at an effective net price of $1.80 + $0.20 - $0.05 = $1.95 per MMBtu.

Financial Market Examples

Swaps

If a party wants to fix a particular price over a period of several years, it might consider using a swap. However, to enter into a swap, the party must have an excellent credit rating and a counterparty must be found that is interested in similar terms and conditions. As an example of how a swap can be used, consider an investment bank that matches a producer seeking to fix a price of $2.00 per million Btu (MMBtu) for 3 years with an end user seeking to fix a price of $2.01 per MMBtu for the same time period. Payments are exchanged between the producer and the bank and between the end user and the bank throughout the term of the contract, depending on the price of gas in each delivery month.

- **Case 1:** The spot price is higher than both "fixed" prices, for example, $2.15 per MMBtu
  - The producer pays the bank $2.15 - $2.00 = $0.15 per MMBtu, foregoing the extra profit that could have been earned.
  - The bank pays the end user $2.15 - $2.01 = $0.14 per MMBtu, enabling the end user in effect to pay only $2.01 for the gas it purchases on the cash market.
  - The bank receives $0.01 more per MMBtu from the producer than it paid to the end user. It keeps this amount.

- **Case 2:** The spot price is lower than both "fixed" prices, for example, $1.80 per MMBtu
  - The bank pays the producer $2.00 - $1.80 = $0.20 per MMBtu, enabling the producer in effect to sell gas on the cash market at $2.00 per MMBtu.
  - The end user pays the bank $2.01 - $1.80 = $0.21 per MMBtu, foregoing the savings from the lower price on the cash market.
  - The bank receives $0.01 more per MMBtu from the end user than it paid to the producer. It keeps this amount.

- **Case 3:** The spot price equals one of the "fixed" prices
  - If the price is $2.00, there is no exchange of payments between the bank and the producer. The end user pays the bank $2.01 - $2.00 = $0.01 per MMBtu.
  - If the price is $2.01, the producer pays the bank $2.01 - $2.00 = $0.01 per MMBtu. There is no exchange of payments between the bank and the end user.
  - The bank receives payments from either the producer or purchaser of $0.01 per MMBtu.

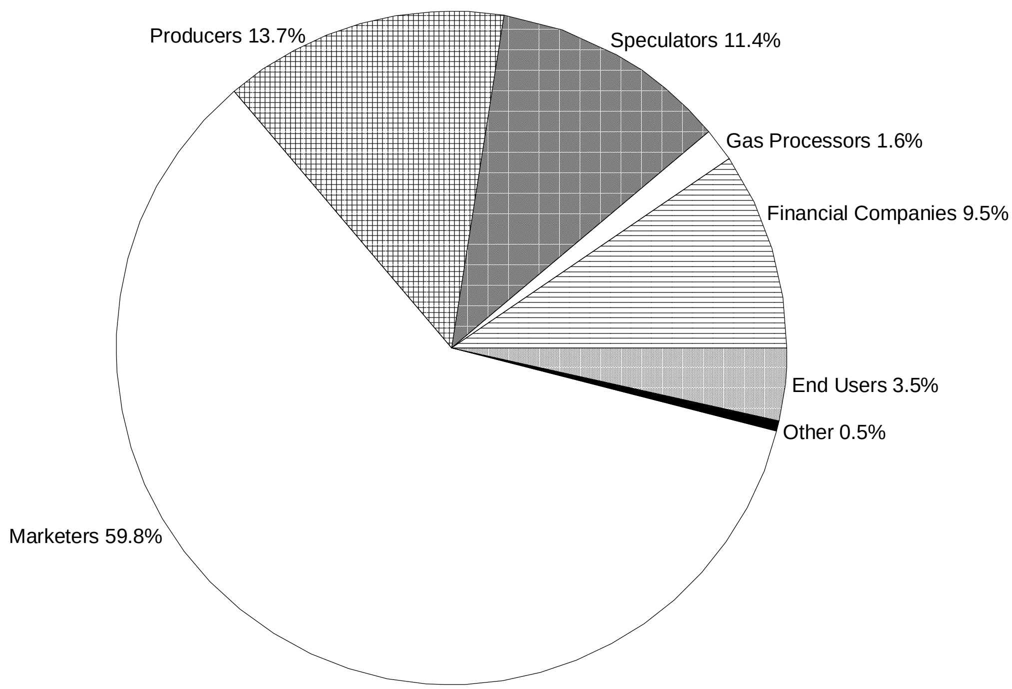
Comparison of the Three Financial Tools

- **Futures**
  - Whether prices moved favorably or unfavorably, the producer was able to sell gas at an effective price of $2.00 per MMBtu.
  - The producer had to provide sufficient margin to maintain its position in the futures market as the value of the futures contract changed over time.
  - Any transaction costs would have to be paid for out of the effective selling price.

- **Options**
  - When the price move was favorable, the producer benefited partially, selling gas at an effective price of $2.10 per MMBtu. The fee for the option was accounted for, but other transaction costs were not.
  - When the price move was not favorable, the producer was partially protected, selling gas at an effective price of $1.95 per MMBtu. The fee for the option was accounted for, but other transaction costs were not.

- **Swaps**
  - Whether prices moved favorably or unfavorably, the producer was able to sell gas at an effective price of $2.00 per MMBtu, and the end user was able to buy gas at the effective price of $2.01 per MMBtu. The bank received income from each transaction.

Figure 19. Participation in the Natural Gas Futures Market by Industry Segment, 1993



Note: Other includes pipeline companies with 0.4 percent, and local distribution companies with 0.1 percent.
Source: New York Mercantile Exchange.

otherwise unwilling or unable to make delivery of gas under a contract.[34]

"Supply diversity" clauses. Some buyers now require regional supply diversity provisions in contracts to ensure that the seller maintains geographically diverse sources of supply to deal with weather-related supply disruptions or localized capacity bottlenecks.[35]

"Gas diversion" clauses. Other clauses reflect the increased sophistication of the gas industry. Buyers realize that marketers deal with many buyers with different requirements and are aware of changes in the current needs of these customers. Thus, a marketer can use gas diversion clauses in order to divert gas intended for one customer to satisfy an unexpected increase in demand from another customer.[36] Because gas diversion clauses are relatively new to the market, they are implemented in a variety of ways. For example, some marketers use them in contracts with high-priority customers who want extra supply security. The cost of this service to the customer is embedded in the reservation fee. Marketers complement these agreements with contracts with fuel-switching customers who agree to have some of their gas diverted as long as the marketing company will pay them the current differential cost of switching from natural gas to an alternative fuel. Thus, under a gas diversion clause the high-priority customer receives gas and the lower priority customer is fully reimbursed for any additional costs of fuel switching.

Creditworthiness

Another way for two parties to guard against the possibility of nonperformance is to assess each other's underlying credit-

[34]John Gregg, "Getting Your Mind Right! Gas Supply Contracting Without a Safety Net," *Public Utilities Fortnightly* (Washington, DC, October 1992), pp. 31-33.

[35]John C. Herbert, "New Features in Long-Term Contracts from Order 636," *Natural Gas* (April 1993), pp. 6-10.

[36]"New Features in Long-Term Contracts from Order 636," *Natural Gas* (April 1993), pp. 6-10.

worthiness. For example, expectations about the seller's performance may be based, in part, on the seller's annual deliveries relative to its existing reserves. The buyer, on the other hand, is evaluated by its ability to make payments from current and expected income. Because performance may take the form of a payment equivalent to the amount of gas stipulated in the contract at current prices, the financial integrity of the seller is also important. For example, if the seller is unable to deliver the amount of natural gas indicated in the contract, the contract may specify that the seller pay the buyer sufficient funds to obtain replacement gas from another source.

The establishment of creditworthiness is often a time-consuming component of the natural gas contracting process. But time spent in establishing creditworthiness is saved later in more efficient contracting for gas shipments. If the company is an affiliate of another larger, possibly more creditworthy, parent company, then the parent company may be asked to guarantee any debt stemming from the contract.

Use of Underground Storage

Companies can also address supply reliability by contracting for storage services. This strategy can be effectively used by both the purchaser and the seller. Underground storage facilities are most frequently situated near major consuming or major producing areas. An end user in Ohio, for example, frequently contracts for storage services from a nearby storage operator in Ohio or Pennsylvania in order to obtain gas on peak days, when the pipeline system from producing areas is operating at full capacity. In turn, a producer may develop storage close to the producing area as a backup in case production problems develop, such as well freezeoffs.

The recent upswing in the number of storage operations in producing regions has increased greatly the reliability of gas supplies because many of these storage operations are salt dome storage with high deliverability and because producers use many of these facilities, in effect, to augment production capacity. (See Chapter 4 for a discussion of current storage capacity.)

Storage service contracts enable the end user to minimize the need for expensive swing contracts or other peaking service contracts. The availability of storage in production areas also enables producers to avoid purchasing gas from other producing companies during peak demand periods when gas is expensive. Underground storage is an excellent way to manage both daily and seasonal supply risks, yet it is costly to use for price risk management because the cost of storing gas can easily add a dollar per thousand cubic feet or more to the price.[37]

[37]Energy Information Administration, "The Expanding Role of Underground Storage," *Natural Gas Monthly*, October 1993, DOE/EIA-0130(93/10) (Washington, DC, October 1993); and "New Projects Are Abundant But Is the Need There?" *Gas Daily's Gas Storage Report* (Rosslyn, VA: Pasha Publications, May 1993), pp. 1-12.

Natural Gas Transportation Contracts

Under Order 636, the transportation services that had become available under open access regulation continue, but have been augmented by a variety of new services. Pipeline companies continue to offer firm service, limited firm service,[38] and interruptible service. Under Order 636, most customers who formerly had firm bundled sales service from the pipeline companies converted their contracts to firm transportation. Both these new shippers and experienced transportation customers will need to use some of the new services offered by pipeline companies, such as balancing, storage, and no-notice service. In addition, the capacity release program instituted by Order 636 offers all industry participants a new option for obtaining transportation services, either on a long-term or short-term basis.

Using New Transportation Services

Many of the new services have been made available because of changes in pipeline company operations resulting from unbundling.[39] Formerly, as owners of the gas in their systems, pipeline companies had been able to use storage and direct the flow of gas to meet customer demands, even if customers exceeded scheduled volumes. Today, because pipeline companies generally do not own the gas flowing through their systems, they cannot use gas belonging to one shipper to compensate for an unexpected change in demand from another shipper. Thus new services have been developed to provide shippers with alternatives to incurring operation-related penalties and to help the industry better manage gas flows under individual contracts.

To understand how some of these services may be used, it is useful first to describe how a transportation contract is implemented. The process begins when the shipper obtains capacity from a pipeline company or through capacity release. Once a shipper has a right to use capacity, it *nominates*, in writing or in electronic form, the daily amount of gas it wants to be received, delivered, or stored by the pipeline company. The shipper nominates capacity at specific receipt and delivery points along the pipeline system. The nomination of daily volumes may be renewed or changed on a monthly basis and

[38]Limited firm service is firm service that is subject to interruption for a specified amount of time each month—up to 10 days is possible. The service is designed to offer a less expensive, firm service to customers who can tolerate a greater risk of interruption, such as those with fuel-switching capability.

[39]The information in this section is based on Interstate Natural Gas Pipeline Association (INGAA), *Interstate Pipeline Services For Customers After Restructuring*, Report No. 93-5 (December 1993), and discussions with INGAA staff.

may be for any quantity up to the maximum daily quantity (MDQ) specified in the contract.

Next, the pipeline company *confirms* each shipper's nomination and inquires into any needed changes. Because there are many shippers making nominations, the pipeline company must look at the aggregate quantities and determine whether the pipeline system can tolerate the overall level of nominations during the confirmation process.

Once the pipeline company ascertains that the system can handle all shipper nominations, it *schedules* the gas, specifying gas flows in and out of each receipt and delivery point. The pipeline company determines priorities based upon type of service. For example, firm service will be scheduled ahead of interruptible service, and primary delivery points ahead of secondary.

The penalties included in today's transportation contracts are intended to encourage shippers to make their gas flows match the quantities for which they have contracted on both a daily and a monthly basis. Such penalties include:

- Scheduling variance penalties—incurred when the daily flow of a shipper's gas does not match the nomination level

- Overrun penalties—incurred when the shipper's maximum daily quantity is exceeded

- Imbalance penalties—incurred at the end of the month if total receipts into the pipeline do not match total deliveries to the shipper.

No penalty will be assessed if the shipper keeps its gas flows within the tolerance levels stipulated in the transportation contract. Tolerances are typically set at 5 to 10 percent so that a shipper may, for example, be slightly above or below its nomination level on a given day and not incur a scheduling variance penalty. The shipper must be aware, however, that even if it remains within the daily tolerance level, the buildup of variances during a month may result in an imbalance penalty at the end of the month.

A pipeline company may choose to waive penalties depending on the cause of the variance and whether or not operational difficulties were created. Generally, however, shippers can monitor their gas flows so that penalties are not incurred, and use other services to augment the firm transportation contract and avoid penalties. The options a shipper may choose from include:

- Purchasing no-notice service

- Requesting overrun authorization

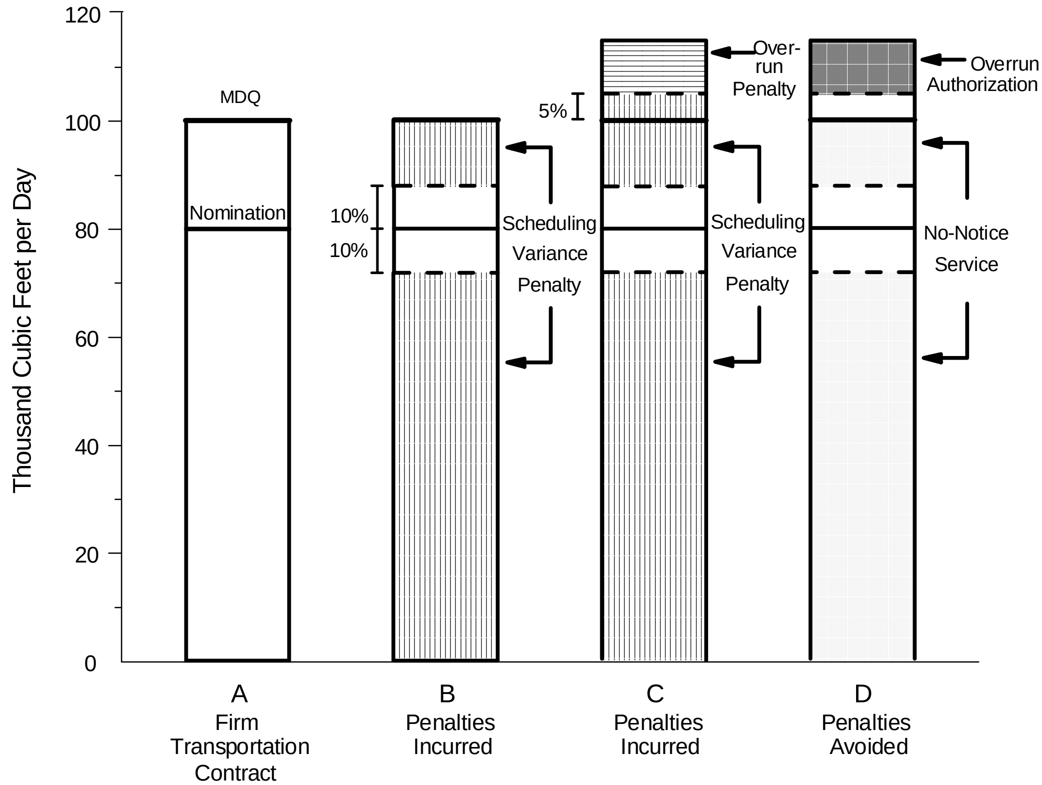
- Arranging to be covered by an operational balancing agreement (OBA).[40]

Shippers can use a combination of services, system monitoring, and a nomination level that provides them with the least-cost means of obtaining gas transportation. Some shippers, for example an industrial customer with a fairly constant demand for gas, may feel they have little risk of incurring penalties. For such customers, the least-cost approach may simply be to pay an occasional penalty rather than to acquire another contract to protect against a limited risk. For other shippers, the potential penalties may be sufficient to warrant contracting for additional protection.

To see how supplemental contracts may be used to avoid daily penalties, consider the case of a firm shipper with a weather-sensitive load, such as an LDC serving mainly residential and commercial customers (Figure 20). To meet peak demand, this LDC has a firm transportation contract with an MDQ of 100 thousand cubic feet (Mcf) per day. Assume that it is early in the heating season so that the LDC only nominates 80 Mcf per day to be delivered during the month (Figure 20, Example A). If the contract specifies a 10-percent scheduling tolerance, then the LDC may take anywhere from 72 to 88 Mcf per day without incurring a scheduling variance penalty (Example B). If a cold snap hits the region, the LDC may find it not only has to exceed its scheduling tolerance, but may have to exceed its MDQ, possibly incurring an overrun penalty (Example C). If the overrun tolerance is 5 percent, then the LDC can take up to 105 Mcf per day and still only incur the scheduling variance penalty. If the LDC takes more than 105 Mcf per day, it will also incur an overrun penalty.

[40]Through an operational balancing agreement, the operators of interconnection facilities will resolve imbalances throughout the month among multiple shippers, so that individual shippers do not incur an imbalance penalty at that point.

Figure 20. Transportation Penalties: Incurrence and Avoidance



MDQ = Maximum daily quantity.
Source: Energy Information Administration, Office of Oil and Gas.

Depending on the LDC's expectations of demand variance, its ability to track gas use on its system, and its experience in supply and transportation contracting, the LDC may choose to use only a firm transportation contract and run the risk of incurring penalties, or it may choose to purchase other services. For example, a no-notice service contract with the pipeline company would enable the LDC to take quantities of gas below or above its scheduling tolerance, up to its MDQ, without incurring a penalty (Example D). However, under such a contract, the LDC must make its own supply arrangements by obtaining enough gas and storage capacity to meet its no-notice demand. It will also have to bring its deliveries back into tolerance within a given time period. The LDC can avoid the overrun penalty by requesting overrun authorization from the pipeline company.

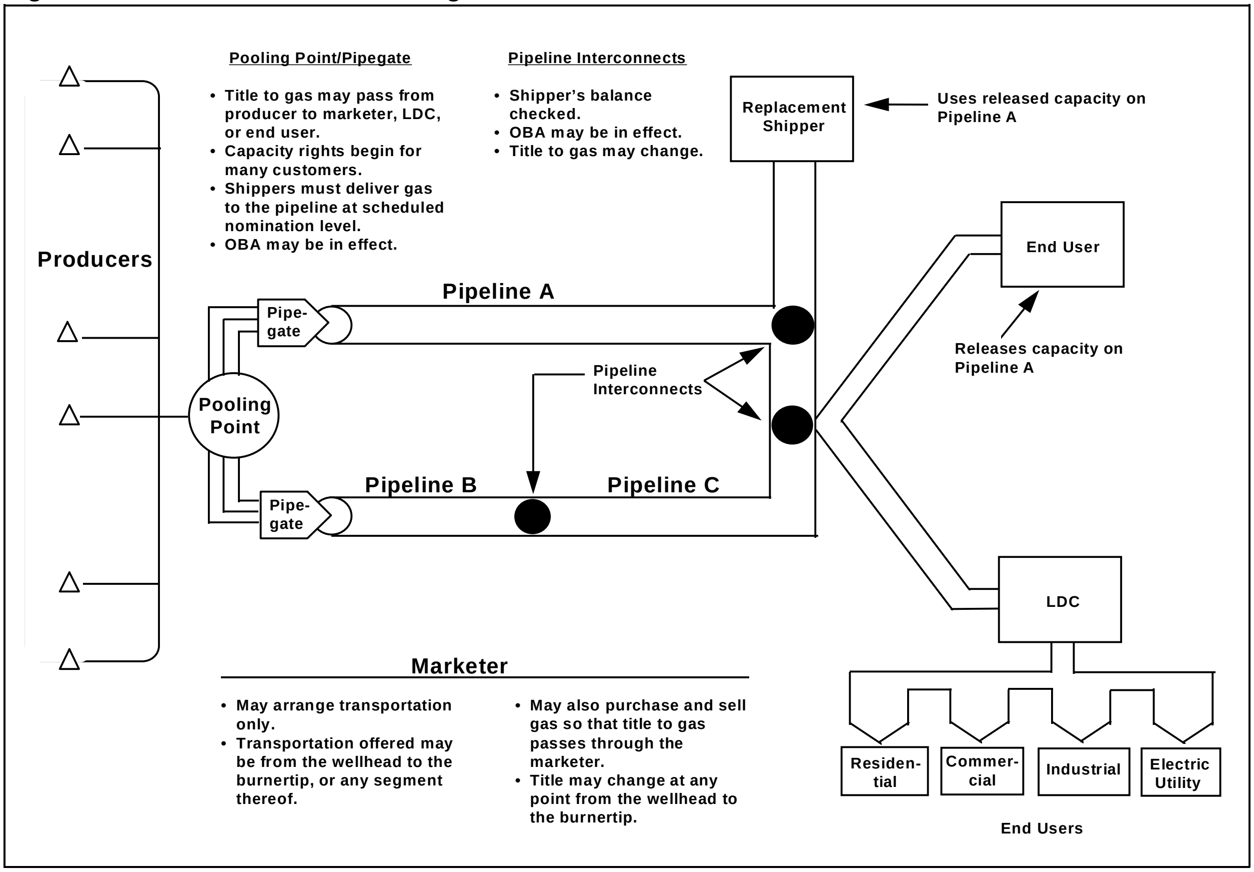
An alternative to careful monitoring or the use of supplemental contracts to avoid penalties is to contract with a marketer for transportation services. For a fee, the marketer will see that the customer's gas requirements are met and will take responsibility for any penalties that are incurred. The marketer, like any shipper, will attempt to minimize penalties, for example, by choosing a transportation path covered by OBA's.

The opportunities and complexities of gas transportation today go beyond the issue of penalties. A discussion of the wider issues involved in gas transportation is presented in the following section.

Moving Gas—Wellhead to Burnertip

The process of obtaining natural gas has changed radically for downstream customers who formerly took title to the gas at a market area delivery point. Customers now have the opportunity to evaluate the costs of purchasing gas from different regions and transporting it along different pipeline systems. However evaluating these choices, and monitoring gas flows, or obtaining contracts to avoid operational penalties, also represent a cost for the gas customer. Marketers offer a variety of services, and some even offer a combination of gas sales and transportation that mimics the bundled service formerly offered by pipeline companies. The

Figure 21. Natural Gas Contracting Paths



LDC = Local distribution company. OBA = Operational balancing agreement.
Source: Energy Information Administration, Office of Oil and Gas.

capacity release program of Order 636 offers yet another transportation option to the industry—the opportunity for the releasing shipper to recover some costs, and the opportunity for replacement shippers to obtain a higher quality of service or to use a different transportation route than would otherwise be available. The myriad of choices faced by gas customers today can best be illustrated by some examples.

An End User—Contracting Directly

Many end users gained experience in arranging separate supply and transportation contracts under open access. For example (Figure 21), an end user follows wellhead prices and purchases the most economical gas it can find, considering the price of the commodity and the feasible transportation routes to its facility. While some gas purchasers may buy gas at a pooling point, where the price will include a markup for transportation from the production area, this end user buys gas at the wellhead and makes its own arrangements for transportation on a gathering line from the production area to the pipegate of Pipeline A. The end user then becomes a shipper on Pipeline A by entering into a firm transportation contract to have the gas moved to its facility along Pipeline A.

However, if the end user sees that its gas requirements will be reduced for a period of time, it may want to take advantage of the capacity release program instituted by Order 636. The end user would announce on Pipeline A's electronic bulletin board that it has a certain amount of capacity for release during a specified period of time. Pipeline Company A would evaluate all the bids that are received for this release package and award the capacity to the replacement shipper with the best bid. If all parties satisfy their obligations under the release contract (see box, p. 71), then:

- The end user, or releasing shipper, would receive some reimbursement for the reservation charge it is paying for unneeded capacity.

- The replacement shipper would receive transportation service it could not otherwise obtain.

Liabilities Under Capacity Release

The capacity release program of Order 636 introduced a whole new area of contracting for the natural gas market. When a shipper releases capacity, complex issues arise as to the releasing and replacement shippers' obligations under the original transportation contract.

The Releasing Shipper Is Liable for the Reservation Charge

The releasing shipper's liability depends upon the contract between the releasing shipper and the pipeline company. When a replacement shipper is awarded released capacity, the replacement shipper is responsible for paying the bid amount, which is the replacement shipper's reservation charge. However, Order 636-A holds the releasing shipper liable to the pipeline company for debts such as the shipper's reservation charge. Thus, the releasing shipper must pay any portion of the reservation charge not covered by the replacement shipper's bid amount. Also, it must compensate the pipeline company for any failure of the replacement shipper to pay its reservation charge, up to the releasing shipper's original charge. In some cases, the pipeline company may agree to amend the contract to shift liability to the replacement shipper. Such a shift of liability may become common where the capacity release is permanent (i.e., for the remainder of the contract term). Even in cases where the pipeline company markets the capacity that is released, the releasing shipper, not the pipeline company, is liable for the reservation charge.

FERC has stated that the rate used to calculate the replacement shipper's reservation charge cannot be higher than the maximum rate for the pipeline company's firm transportation service. The releasing shipper receives credit for the reservation fee paid by the replacement shipper to the pipeline company. If the fee paid by the replacement shipper is higher than that owed by the releasing shipper, the releasing shipper keeps the difference.

The Replacement Shipper Is Liable for Usage Charges

In addition to the bid amount, the replacement shipper is responsible for all transportation usage charges, any surcharge on the usage charge, and any penalties. There are two main contractual issues with regard to the usage fee. First, if a pipeline company offers a usage discount to the releasing shipper, it is not required to offer the same discount to the replacement shipper. Second, the releasing shipper is not liable for the replacement shipper's failure to pay usage charges. Pipeline companies therefore bear the risk that replacement shippers may default on usage charges (or on penalties and late charges unrelated to the reservation charge). In order to clarify the replacement shipper's responsibilities and mitigate possible risks, pipeline companies may require replacement shippers to execute a contract for the released capacity as soon as possible after the bid has been awarded. Pipeline companies need to implement procedures to cover situations where the replacement shipper defaults and the releasing shipper needs to terminate the release.

- The pipeline company would earn income from higher throughput on its system than would have occurred without the release program.

An LDC—Using a Marketer

Prior to Order 636 many gas users obtained their gas through a single bundled sales contract with a pipeline company. Consider, an LDC that had such a contract through its single pipeline supplier, Pipeline C (Figure 21). Being inexperienced at tracking wellhead prices and evaluating transportation options, the LDC now seeks a marketer that can rebundle the sales and transportation services it needs. The marketer may decide to supply this LDC with gas it can obtain under contract with producers or with gas it has already transported to a pooling point. The marketer evaluates all the transportation options and chooses to serve the LDC through Pipelines B and C because an operational balancing agreement is in place at the interconnection between these two pipelines. Thus the marketer, who is the shipper under the transportation contracts, will be protected from any imbalance penalties. The fee charged by the marketer will reflect the cost of satisfying the LDC's requirements, including the options the marketer chooses for dealing with scheduling variances created by shifts in demand on the part of the LDC.

When choosing a transportation service, shippers must evaluate not only the transportation rates charged by different pipeline companies, but the quality of the related services offered, such as no-notice, and the feasibility of different routes for bringing purchased supplies to the delivery point.

The Portfolio Decision

The previous sections addressed separately most aspects of supply (or commodity) contracts, transportation capacity contracts, and financial contracts. This was done to isolate important features of these contracts and to emphasize that many buyers negotiate contracts with different parties when obtaining these services. However, buyers of gas must consider the contracts as a group to ensure that the set of contracts reliably and economically satisfies their specific requirements for gas service as well as other management objectives.

The important differences between supply and transportation markets are also reflected in the development of contract portfolios. First, buyers usually have numerous choices for supply acquisition, either purchasing directly from a producer in a supply area or from a pooling point. However, capacity access is more limited. A buyer usually has access to only a few long-distance interstate pipeline systems for moving the gas from the original purchase site. Second, purchasers are faced with substantial variability in prices on a day-to-day basis. Commodity prices are unregulated and show rapid responses to changes in market conditions. Buyers typically enter into contracts for less than 2 years to ensure that costs of the commodity closely reflect market conditions. In contrast, transportation rates can fluctuate as well, but within a minimum and maximum range set by FERC. Because of the greater price stability and the capacity release market, customers are more likely to sign longer term contracts (5 or more years) for transportation services.

A gas purchaser must consider all contracts within the context of a portfolio of contracts for gas services to ensure that:

- Expected demands for a planning period are covered by contracts for gas supply and for pipeline capacity.
- Periods of peak demand are supported by contracts for highly reliable sources of gas supply and pipeline capacity.
- Contracts are diversified as to the length or term of the contract to enable the company to benefit from advantageous price movements.
- Contracts are diversified across locations to promote supply reliability.
- Sufficient contracts are being used for balancing, nominating, and scheduling services if problems are anticipated in these areas.
- Price risk protection is incorporated where appropriate.
- Overall costs are minimized, taking into account the level of service required.
- The cost of gas service will, over the long term, closely follow the overall market.

Reliability and Price

In developing a contract portfolio, purchasers face numerous tradeoffs between supply reliability and price. The decisions made by each company are tied to its own or its customers' seasonal demands (load profile) for natural gas, and the company's location and size (see box, p. 73).

Fuel-Switching Customers

For companies with fuel-switching facilities, the most important consideration may be obtaining fuel at the lowest cost. Supply reliability can be effectively handled by their ability to switch quickly to an alternative fuel. This capability was itself obtained through a tradeoff between reliability of energy service and cost. In this tradeoff, the gain from being able to purchase energy in the oil and gas market was calculated to be greater than the cost of investing in fuel-switching and oil storage equipment.

The portfolio held by this type of company would be focused on short-term supply contracts closely tracking market prices and low-cost transportation contracts. Because of the company's capability to switch to an alternative fuel, it can afford the risk of getting bumped off a pipeline system and would thus choose the relatively inexpensive interruptible capacity contract, or obtain released capacity.

Large Industrial Customers

The decisions facing a large industrial customer, such as a chemical manufacturing plant using natural gas as a feedstock, can be quite different. This plant needs a reliable

Hypothetical Examples of Portfolio Selection by Different Companies

Companies have diverse requirements for gas service, which are reflected in their selection of contracts. The following simplified examples illustrate what might be contained in a contract portfolio for several different types of companies with diverse requirements.

1. Electric Utility with a Dual-fired Peaking Unit

A simple case might be an electric utility with a dual-fired oil and gas peaking unit, which is primarily used to serve residential and commercial customers with a summer peak cooling load. The principal goal of the utility is to minimize cost of fuel for this unit. The utility also has storage facilities for oil. This utility might have the following types of contracts in its portfolio:

- Market based short-term contracts for both oil and gas
- Interruptible or release capacity contracts for transportation.

This customer has the advantage of having its major peak demand for residential/commercial cooling services during the summer when pipeline capacity and supplies are usually available. The utility depends on its oil storage facilities for guaranteeing reliability of supply.

2. Electric Utility with Large Residential and Commercial Load

The electric utility is in a major producing region and has both residential/commercial summer space-cooling and winter space-heating peak demands. Much of its load is satisfied by a coal-fired baseload plant. However, it has several natural gas peaking plants that it uses to satisfy core customer peak loads, especially during the summer when for environmental reasons it must reduce the utilization of its coal plant. This utility might have the following types of contracts in its portfolio:

- Firm transportation contracts to ensure reliability of supply, especially during the summer
- Mid-term commodity contracts, which are indexed to a spot price of gas to obtain a current market price
- Short-term contracts with a variety of suppliers who make monthly offers of supply, which the utility either accepts or rejects depending on price, for any incremental supply needs
- Interruptible transporation contracts to support some of its short-term contracts.

The company has a further advantage of owning natural gas reserves, which enables it to increase its use of gas readily during the summer and to sell supplies from these reserves during the spring and fall.

3. Consortium of Municipal Gas Companies Serving a Region with a Temperate Climate

The example consortium comprises municipal gas distribution companies in the South with relatively flat demand for gas during the year, but some modest seasonal demand between late November and early February. This consortium is also a part owner of a storage facility in a producing region. A portfolio to meet the consortium needs might have the following types of contracts:

- Firm transportation contracts to ensure the shipment of gas from storage and from producers
- Short-term commodity contracts with producers to obtain the best market prices available
- A swap contract to hedge the price risk on the gas it has in storage.

The consortium has the advantage of being able to rely on its own storage for balancing and as a means of guaranteeing supplies of natural gas to its customers.

4. Midwest Local Distribution Company (LDC) with a Large Seasonal Load

The example LDC in the Midwest serves mainly residential and commercial customers, who account for approximately 75 percent of its annual demand for gas. These customers have a dramatic rise in space-heating demand between late October and early March. The LDC might have the following types of contracts in its portfolio:

- Mid-term commodity contracts of various terms, which are negotiated regularly as they expire in an attempt by the company to remain competitive
- A long-term storage capacity contract, which enables the company to serve its core customers reliably during the winter
- Firm transportation contracts, which it relies on extensively for the majority of its gas shipments
- Interruptible transportation contracts, which it uses only in the nonheating season;
- A contract with a marketing company to obtain balancing services.

This company may consider trading on the futures and related financial markets to stabilize prices.

supply of natural gas at a price that does not deviate significantly from the price it can charge for its product. Furthermore, like most industrial customers, the plant's gas requirements are relatively constant throughout the year. Thus, the company will likely have a mixture of mid-term contracts, to ensure service during the winter heating season, and short-term contracts, to take advantage of lower prices in the off-season. Because of its fairly predictable demand, the industrial customer may have little difficulty keeping within delivery tolerances and may not be concerned with additional contractual arrangements to reduce imbalance penalties.

This particular type of company may be very active in the financial markets to ensure predictable supply costs. It may obtain financial contracts that are tied to the price of its output, thus, ensuring that input costs do not increase more than the price it can charge for its output. Other industrial customers whose gas costs are a much smaller percentage of their product costs are much less likely to engage in the natural gas futures and related financial markets.

Local Distribution Companies

Unlike the relatively constant requirements of the industrial customer, the load profile of a distribution company, especially in the northern United States, varies widely throughout the year. The larger the proportion of residential and commercial space-heating customers to total customers, the more variable the load profile. Security of supply to meet residential and commercial load during the heating season takes the highest priority in the LDC's portfolio decisions. For the heating season, the LDC will contract for firm supplies and transportation to ensure that deliverability is not a problem. In addition to acquiring gas from the supply areas or pooling points, contracts for storage are an essential part of the strategy for meeting heating season demand.

The LDC must plan not only for the normal variation in weather but also for periods of extreme weather when the demand peaks far above normal. Its ability to meet peak demands is of special concern, both because the LDC may have to contract for very expensive gas to meet this demand and because the contracts used to satisfy this demand are examined closely by its public utility commission (PUC). Because sources of supply such as salt dome storage offer high deliverability and very reliable service, the existence of such contracts in a portfolio to cover peak-demand periods may be viewed quite favorably by a PUC, even though the cost of gas under such contracts is very high.

To satisfy peak demand, the LDC may also have other relatively expensive contracts for liquefied natural gas (LNG), no-notice service, and swing service with highly variable takes in its portfolio. During the off-peak season, however, the LDC can obtain gas under short- or mid-term contracts and use its reserved transportation capacity to move the gas into storage. With highly variable and unpredictable demand, the LDC is likely to be concerned with imbalances and overrun problems and may find it useful to contract for some protection from penalties associated with these problems.

While deliverability is of prime concern to an LDC, the price of gas to its customers also is carefully weighed in its decisions. It must be able to demonstrate to the PUC that it has obtained a low cost for its residential and commercial customers, but must also be able to offer competitive enough rates to retain its fuel-switchable industrial and electric utility customers as well as those customers capable of bypassing the LDC for its gas supplies. For example, Atlanta Gas Light Company lost about 8 percent of its annual deliveries in 1993 when it lost one customer capable of bypass.[41] Such a loss of customers can lead to increased gas costs for the remaining customers.

Electric Utilities

Electric utilities are also large consumers of natural gas. In contrast to many LDC's, their demand for natural gas tends to peak in the summer to meet their customers' air-conditioning requirements. Since many utilities regularly use alternative sources of energy, including electricity from cogenerators and from other utilities, their focus is on the price of natural gas relative to alternative energy sources. Thus, portfolios of electric utilities will in this respect be similar to those of large industrial users.

Supply reliability is a major factor in an electric utility's portfolio decisions. The utility obtains reliability from previous capital expenditures, such as those that enable it to store oil and to substitute oil for natural gas. Some electric utilities also obtain supply reliability by having a contract to receive natural gas from underground storage reservoirs during the summer. This situation enables the utility to enter the short-term market aggressively for some of its summer gas supplies. If the price of gas remains low relative to the price of oil, then the utility will also attempt to extend the term of its gas contracts and decrease the term of its oil contracts. With a diverse supply of alternative energy sources to ensure supply reliability, their portfolios will tend to concentrate on short-term supplies of gas reflecting market conditions and low-cost transportation arrangements.

With the Clean Air Act legislation, environmental regulations are an added issue for many utilities. For example, some utilities in California are required to burn natural gas during certain times of the year. This requirement substantially affects their portfolio decisions. In this situation, assuring adequate supplies may be weighted more heavily than price in their portfolio decisions.

[41] Joanne M. Fairechio and Donald D. Dufresne, "Atlantic Gas Light—Strong Growth Market: Victim of Adverse Regulation," *Natural Gas Distribution* (New York: Salomon Brothers, March 7, 1994).

Marketing Companies

To the extent that marketing companies provide gas services to any of the previously discussed customers, their portfolio development will share the same characteristics. Perhaps the most notable difference is the extent to which marketers use the futures and other financial markets. As noted earlier, marketing companies are the most active users of the natural gas futures market and probably of other natural gas financial instruments as well. For example, some marketers also contribute to the growth of the financial market by writing unregulated option and swap contracts.

Financial contracts overlay both supply and purchase contracts for marketers, enabling them to control price risk. This very active engagement in the futures market enables them to lock in a profit for providing marketing services. In addition, by controlling price risk, they are better able to ensure that they are satisfactorily providing the myriad of services needed in today's market. While many LDC's are not active in the futures market, to the extent that they use the services of marketers, their contracts with marketers are in effect supported by activity in the futures market.

Because they provide services to both sellers and purchasers of natural gas, marketers are in a unique position with respect to trading in the futures market, often obtaining futures contracts to buy and sell gas in the same transaction. Many large buyers of gas regularly obtain futures contracts to buy gas to protect themselves from price increases. Yet, these customers incur the cost of having to post additional collateral (margin) with their broker if prices decline. For some buyers and sellers, the chance that these additional margin requirements will be large is significant.[42] Because marketers have both buy and sell positions on the futures market, they are not as exposed to this risk as other buyers and sellers of gas. A portion of their overall position is debited daily for deficient margin amounts, but another portion is also credited daily for excess margin amounts. Thus, the overall amount of their margin usually changes slightly between days and is usually a very small portion of their overall trading position. This situation, in part, explains the much greater involvement in the futures market by marketing companies.

Other Factors in the Portfolio Decision

Although reliability and price are typically the key criteria used in creating a portfolio of contracts, diversity and the term of the contract are also important. One of the major opportunities provided by the gas industry today is the availability of contracts with a variety of contract lengths. If all contracts were to terminate on the same date, then all replacement contracts would, in part, reflect expectations about the future at that time. However, if the contract terms are staggered, the contracts making up the portfolio will reflect a variety of conditions and expectations about the future, and provide the likelihood that the overall price paid by the purchaser will more closely follow the overall movement of the market.

Other administrative and logistical reasons also favor staggering contract terms. The administrative costs of negotiating contracts and the planning costs of integrating contracts into the use or distribution of gas are more manageable under these conditions, and companies can make incremental adjustments in their portfolios. Effective staggering of contracts can even reduce the need for special provisions in contracts, such as the evergreen clauses previously discussed. Because the buyer pays for these provisions, the cost of gas under the contract can be reduced if such options are eliminated.

Today's transportation portfolio will also reflect the need to avoid imbalance penalties, which are imposed by pipeline companies to maintain the integrity of the system. For purchasers with highly variable requirements throughout the year, their portfolios will either contain new types of contracts with provisions to avoid such penalties or general service contracts with marketing companies that include such services. Some companies will also have contracts for nominating and scheduling shipments of gas, while others will have contracts for the documentation of all scheduling and shipping activities. It is important to consider these newer types of contracts in portfolio development because they allow closer management of the allocation and distribution of gas and, thus, may lead to overall efficiency and supply reliability gains for the industry. Even though these contracts represent an additional cost initially, eventual savings may far surpass these costs.

The Use of Financial Contracts in the Portfolio

For many companies, the financial market affords them price risk protection as well as a very liquid market for restructuring their financial contracts as market conditions and their business strategies change.

The liquidity, or the ability to change a risk position with another party (such as the risk of holding gas), in options and futures contracts is in contrast to the lack of liquidity in most contracts for the physical commodity. In the physicals market, if an industry participant agrees to buy gas, it cannot readily change this position without incurring substantial costs. In

[42]Arthur Gottschalk, "German Giant's Trade Woes Make Waves in Swap Mart," *Journal of Commerce* (February 3, 1994), and "Anatomy of the Metallgesellschaft Debacle," *Derivative Risk Analyst* (March 1994).

contrast, a buyer of a gas futures contract can readily sell the futures contract at a market rate at any time and thus close out its position.

Buyers of gas use the financial market to alter the price side of their portfolio in a number of ways. For example, a firm with a long-term gas contract that is indexed to a monthly cash price may find that the contract is causing budgetary problems because of great variability in the price of gas. The buyer can fix the price of gas through a series of futures contracts or a swap contract and, thus, solve or diminish the budgetary problem at any time.[43]

Most important, however, the financial market provides the industry with a means of price discovery, which facilitates trades in the physical commodity and also facilitates the indexing and evaluation of contracts on a regular basis.

The Dynamic Portfolio

Today, companies have access to many programs and techniques for evaluating and improving their contract portfolios. Extensive market information, especially price information, is also readily available. Companies combine the market information with these programs to find the least-cost portfolio of contracts that also meets their specific requirements for gas service.[44] They must first estimate both current and future gas requirements for peak and nonpeak service, and then assign a value to each service level. Companies can then evaluate alternative portfolio specifications, including contracts of varying terms and price indices and flexibility in delivered volumes, to identify the portfolio that satisfies their requirements at the lowest cost.

Statistical analysis of price data can be used to improve portfolio performance. Thus, gas purchasers use measures of performance, such as the difference between the price they pay and some maximal price they are willing to pay, to evaluate their contracts individually and as part of a portfolio. In particular, the ready availability of historical series for gas prices at different locations enables the application of classical portfolio analysis as used for investments in stocks and bonds, which can improve the overall performance of a portfolio.[45] Purchasers also use the historical information on prices and other market information to evaluate whether the premium to be paid for a particular type of contract is acceptable.[46]

Outlook

The natural gas contract market has become increasingly sophisticated in response to the complexity brought about by the open access regulations under Order 436 and furthered under Order 636. One characteristic of the new contract market is the importance of flexibility in contract provisions, where buyers and sellers want to ensure that their overall portfolio of contracts will closely reflect market conditions over the longer term. Supply contracts being written today no longer contain the inflexible price and volume clauses that precipitated the market disruptions seen during the past 20 years. Instead, the movement towards shorter term contracts, indexed pricing, and take-or-release clauses all provide the flexibility to ensure that contracts for gas purchases and sales reflect current market conditions. No longer are many contracts being written where buyers have an obligation to take large amounts of gas under a long-term commitment even if they cannot sell the gas (take-or-pay-clauses). Instead, large buyers are purchasing gas under short-term or mid-term contracts that give them the flexibility to purchase gas from sellers in regions with the lowest price.

Appropriate valuation of their requirements and the tradeoffs among the various types of contracts available is one of the challenges facing industry participants today. Purchasers who in the past relied on bundled service have little or no experience with this type of portfolio valuation. Initially, it is likely that the industry will take a conservative approach and overvalue some aspects of portfolios. In time and with some experience in the market, this will change and will result in lower costs of serving the markets.

The continuing development of the capacity release market will be an important determinant of the transportation market in the future. Shippers reserving long-term capacity could find that the regulatory price caps on the capacity they release may limit their ability to offset reservation charges. For example, many of the shippers will release capacity during the off-peak periods when the pipeline is typically underutilized. This capacity may have to be severely discounted to be leased. On the other hand, if they have excess capacity during a peak period, they cannot sell it for more than the maximum allowed rate. A replacement shipper may be willing to pay more than the allowed maximum, thus the capacity may be trading for less than the market value and the releasing shipper will not be compensated for this higher value.

[43]David Apsel, "Hedging Long Term Commodity Swaps with Futures," *The Global Finance Journal*, 1, 1 (1989), pp. 77-93.

[44]Mohammad Harunuzzaman and Govindarajan Iyyuni, *GASMIN: Gas Supply Cost Minimization Program* (Columbus, OH: The National Regulatory Research Institute, January 1990).

[45]R. Harrington, *Modern Portfolio Theory*, 2nd ed. (Englewood Cliffs, NJ.: Prentice Hall Inc., 1987).

[46]Frank C. Groves, James A. Read, Jr., and Paul R. Carpenter, "Estimating the Cost of Switching Rights on Natural Gas Pipelines," *Energy Journal*, 10, 4 (1989), pp. 59-81; Laurence Haar "Gas contract valuation model assesses options," *Oil and Gas Journal* (June 4, 1984), p. 72; and Elizabeth Olmsted Teisberg and Thomas J. Teisberg "The Value of Commodity Purchase Contracts with Limited Price Risk," *Energy Journal*, 12, 3 (1991), pp. 109-135.

With all the increasing responsibilities facing the industry, there is opportunity for gain. The ability to choose from many service options should ultimately result in lower costs for natural gas service. Part of the gains will be offset by the increase in transaction costs associated with having to contract for numerous services rather than just one or two. Many new services, financial and otherwise, have been developed to allow customers to manage many new risks associated with the unbundling of pipeline company sales and transportation. Again the ability to evaluate risks appropriately in the context of a company's specific situation will be an important aspect of obtaining lower cost service options and, ultimately, of developing a more efficient contracting market.

4. The Natural Gas Storage Market

Market forces and regulatory changes during the past decade have led to increased awareness of the importance and value of natural gas storage services. Storage has always been an essential component of the transmission and distribution system, augmenting pipeline supplies from the producing regions to meet short-term peak seasonal demands. It is an important link in ensuring supply reliability.

While Order 436 established open access to transportation services, it did not require open access to storage services. The lack of corresponding access to storage became increasingly a concern for those pipeline customers purchasing their own supplies and contracting separately for transportation. The Federal Energy Regulatory Commission (FERC) addressed these concerns in Order 636 and mandated that (1) storage services be unbundled, that is, offered as a distinct service, separately charged and itemized, (2) customers be offered greater access to working gas capacity, and (3) customers be given the opportunity to sublease any of their contracted storage capacity.

Although Order 636 directly affects only interstate storage operations, its impact has been widespread. Approximately two-thirds of all working gas capacity became accessible to customers as a result of the restructuring under Order 636. However, even under Order 636, most interstate pipeline storage will continue to be contracted to previous sales customers, mostly local distribution companies (LDC's) with limited or no storage of their own. If some portion of a pipeline company's storage capacity remains unsold, then new customers (for example, marketers) will be solicited to contract for that storage capacity. Otherwise, new customers may obtain storage capacity through two ways: (1) the capacity release mechanisms set forth in Order 636 whereby customers are able to sublease their unused capacity via electronic bulletin boards (EBB's), and (2) the development of new storage capacity, either from expansion of existing sites or new joint ventures with others.

Today, storage is an important tool for managing the risks associated with the elimination of bundled sales and transportation service. Accordingly, market participants are altering their approaches toward storage to respond to these changing market conditions. For example:

- Inventory management is receiving more emphasis as working gas storage levels are generally lower, but with increased injection and withdrawal activities throughout the year.

- There is increased interest in the development of high-deliverability storage, particularly salt cavern storage, where gas can be quickly withdrawn and then quickly refilled (see box, p. 80).[47] This development is, in part, a response to the overall growth in individual customer transactions, the variety of transportation arrangements that have increased the chances of system imbalances, and the need for a quick response mechanism to manage operations.

- Major natural gas producers are forming storage subsidiaries and developing new storage sites as a way of levelizing production streams and assuring themselves sufficient inventory capacity to support their contractual obligations.

- Independent storage operators are developing storage capacity to provide nontraditional storage services, such as load balancing, to special niche markets. Some of these services were previously obtained by suppliers and customers under the bundled sales and transportation service.

- Marketers, in their roles of aggregating supply and rebundling services, are also entering the storage market to obtain storage capacity to service their contract customers.

- Many of the planned new storage sites are in proximity to the major market hubs being developed.

This chapter examines how these changes affect the use and operation of current storage facilities and the development of new facilities. Storage operations changed substantially after 1985 when the open access environment for transportation services increased competition in the natural gas industry. Additional changes are occurring as bundled sales and transportation services have been replaced by separate contracts for each service. As noted in earlier chapters, customers often must contract for a variety of services associated with storage and transportation arrangements. These services may include supply balancing and emergency backup—services that had

[47]For the purposes of this chapter, a high-deliverability storage facility has been defined as one whose design-day withdrawal rate allows it to draw down its working gas capacity in 20 days or less. In most instances, the principal purpose of high-deliverability storage is to provide peaking or load balancing services. While salt cavern storage is often used synonymously with high-deliverability storage, in fact, some depleted gas reservoirs also are capable of high-deliverability rates and are used as peaking facilities. Some have the ability to draw down their working gas in as little as 3 days.

Types of Underground Storage Facilities

The three principal types of underground storage sites used in the United States today are: (1) depleted reservoirs in gas and/or oil fields, (2) aquifers, and (3) salt caverns. Each type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation costs, deliverability rates, cycling capability), which govern their suitability to particular applications.[a]

- **Depleted Gas/Oil Fields.** Depleted gas and oil reservoirs are the most common underground storage sites. They use the pressure of the stored gas and, in some cases, water influx to drive withdrawal operations. The reservoirs are usually designed for one injection and withdrawal cycle per year. Daily deliverability rates from depleted fields vary widely because of differences in the surface facilities, base gas levels, and the fluid flow characteristics of each reservoir. Retention capability, which is the degree to which stored gas is held within the reservoir area, however, is the highest of the three types of underground storage sites. Depleted field storage is also the least expensive to develop, operate, and maintain.

- **Aquifers.** An aquifer storage site is a water-bearing reservoir with particular geological characteristics that allow it to hold natural gas. Aquifers are usually used as storage reservoirs only when depleted gas or oil reservoirs are not available. In general, aquifer storage is more expensive to develop and maintain than depleted gas/oil reservoirs. Unlike a depleted gas/oil field, aquifers require additional facilities, testing, and development time. New facilities must be installed from scratch and extra base gas must be bought and injected since no native gas is present. In addition, while base gas in gas/oil storage reservoirs usually is about 50 percent of total capacity, base gas in aquifer storage may constitute more than 50 percent and as much as 80 to 90 percent by the time the site is fully developed for gas storage. Deliverability rates, while variable, are comparable to gas/oil field storage. Aquifer storage is designed for about one cycle per year.

- **Salt Caverns.** Salt cavern storage is prepared by injecting water (leaching) into a salt formation (either a salt bed or salt dome) and shaping a cavern. Salt beds are more expensive to develop than salt domes because in general they are thinner formations (about 1,000-feet thick versus up to 30,000 feet), which makes them more susceptible to deterioration. Both types of salt facilities are much more expensive to develop than depleted field or aquifer storage, often two to three times more expensive. Because they are susceptible to cavern wall deterioration over time and to salt water incursion, high workover costs may be incurred, as well as additional expenses for special equipment on site. However, deliverability rates are high because a salt cavern is essentially a high-pressure storage vessel (that is, an underground tank). Base gas requirements are low (about 25 percent) and can be withdrawn fully in an emergency. On average, cycling rates range from 4 to 6 times per year, in comparison with 1 to 1.2 cycles for depleted gas/oil field storage, and 0.95 to 1 for aquifer storage. As such, salt cavern storage is well-suited for meeting dramatic swings in demand.

[a]For further information, see Gaz de France, Research and Development Division, Underground Storage Department, *Underground Storages Facilities* (Paris, France, June 1992).

previously been part of the bundled pipeline package. These new requirements as well as projected market growth have sparked plans for a substantial increase in storage deliverability before the turn of the century. This chapter first summarizes the changes already evident in the industry under restructuring. It then discusses customers' needs for new services in response to the implementation of Order 636 and how these needs are being addressed in the development of new storage capacity. The chapter also identifies the regional differences in storage operations as reflected in planned storage additions.

The Operation of the Storage Market Today

Large amounts of interstate storage capacity were opened to transportation customers when Order 636 provisions were fully implemented on November 1, 1993. Order 636 directly affects only interstate storage operations (see box, p. 82). However, interstate pipeline and other FERC jurisdictional storage operators account for 72 percent of total U.S. working gas capacity and 62 percent of daily deliverability from storage

(Table 8). Accordingly, the impact of Order 636 is substantial as nearly two-thirds of all working gas capacity has become accessible to customers as a result of the restructuring.

Even before implementation of Order 636, the percentage of working gas in interstate storage owned by customers of pipeline companies had been growing steadily under the open access provisions of Order 436. The percentage of total working gas in interstate storage owned by customers at the start of the heating season grew from 27 percent in 1986 to 42 percent in 1992.[48] Interstate storage operators, however, still retain 10 to 20 percent of their working gas capacity to meet their system requirements for load balancing, system management, and providing "no-notice" service.[49] As customers have increasingly taken responsibility for contracting for storage services, and thereby managing the costs associated with storage use, there have been significant changes in inventory management practices and, as noted earlier, an increased interest in using facilities, such as salt dome storage, that provide high deliverability and rapid cycling of the inventory.

Inventory Management

In each of the past 3 years, working gas inventory levels at the beginning of the heating season (November 1) have drifted progressively lower, from 3.4 trillion cubic feet (Tcf) in 1991 to 3.0 Tcf in 1993.[50] Working gas inventories at the end of the heating season also dropped significantly in 1992 and 1993, both in volume and as a percentage of working gas capacity. Between 1985 and 1991, end-of-season inventories ranged from 47 to 50 percent of capacity. In contrast, inventories in 1992 were 40 percent of capacity and, after the severe weather in 1993, 31 percent (Figure 22).

In recent years, there has also been a significant increase in the utilization of storage throughout the year. From 1988 through 1992, injections and withdrawals during the heating year averaged 20 and 18 percent higher than during the previous 5-year period (Table 9).[51] Also, average withdrawals per storage field during the heating season increased by 15 percent (unadjusted for weather). After adjusting for weather, a shift is clearly evident (Figure 23). For example, withdrawals in the 1991-92 heating season were 118 billion cubic feet (Bcf) higher than in the 1985-86 heating season. Even greater change occurred in average withdrawal activities during the nonheating season. Offpeak withdrawals averaged 36 percent higher from 1988 through 1992 than during the previous 5-year period. Injection activities have also increased during the heating season. Average injections during heating seasons from 1988 through 1992 were up by 29 percent from the average during the 1983-through-1987 period.

During the severe weather that hit the East Coast in March 1993, storage was heavily utilized and working gas inventories fell to 1.2 Tcf,300 Bcf below year-earlier levels. These low inventories raised some concern in the industry. But by the beginning of the 1993-94 heating season, 83 percent of working gas capacity was filled—the same level as a year earlier.[52] The replenishment of storage began in earnest in April and resulted in unprecedented injection levels.[53] During May 1993, average net injections ran at a record rate of 13.6 Bcf per day, in contrast to the previous high of 11.8 Bcf per day in June 1989.[54] By the latter part of the nonheating season, the storage injection rate had returned to normal levels for the period. Still, from April through October, net storage injections averaged more than 9.8 Bcf per day, the highest level on record.

[48]Energy Information Administration, "Expanding Role of Underground Storage," *Natural Gas Monthly*, DOE/EIA-0130(93/10) (Washington, DC, October 1993), p. 16.

[49]No-notice transportation service allows shippers to receive delivery on demand, up to their firm entitlements, without incurring penalties (see Chapter 2).

[50]Energy Information Administration, *Natural Gas Monthly*, DOE-EIA-0130(94/02) (Washington, DC, February 1994), Table 13.

[51]The majority of open access certificates were granted to interstate pipeline companies after 1987. Thus, storage operations averaged over the period from 1988 through 1992 (when most companies were actually operating under Order 436) are compared with operations during the previous 5-year period, 1983 through 1987.

[52]The level of total working gas capacity in use on November 1, 1993, continued the trend of lower beginning-of-season inventory levels. And, while on a percentage basis, working gas capacity utilization was the same (83 percent) at the beginning of the past two heating seasons, in fact, a significant change had occurred. Several interstate storage operators revised their base gas levels upward (conversely their working gas capacity downward) just before the 1993-94 heating season. This resulted in a 300 Bcf change from working gas to base gas. The adjustment was in response to several FERC ratemaking decisions affecting base gas accounting under Order 636. Without these accounting adjustments, working gas in place on November 1, 1993, would have been 74 percent of working gas capacity, a 9-percent decline from the previous year.

[53]Injection levels were high because (1) the working gas levels were so low that reservoir pressures were down and more gas could be injected at a faster rate, and (2) many operators were anxious to fill storage before the anticipated increase in demand raised prices even further.

[54]Energy Information Administration, "Expanding Role of Underground Storage," *Natural Gas Monthly*, DOE/EIA-0130(93/10) (Washington, DC, October 1993), Table FE4.

Owners of Storage

The principal owners of underground storage facilities are (1) interstate pipeline companies, (2) local distribution companies (LDC's), (3) intrastate pipeline companies, and (4) independent storage service providers. Several natural gas producers and large industrial users also own a limited amount of storage.

- **Interstate pipeline companies** account for 61 percent of all working gas capacity in the United States (Table 8). Historically, these FERC-jurisdictional companies have owned and distributed most of the natural gas from U.S. underground storage sites. Underground storage is particularly important to interstate pipeline companies because they depend heavily on storage inventories to facilitate load balancing and system supply management on their long-haul transmission lines.

- **LDC's and intrastate pipeline companies** account for about 36 percent of working gas capacity. LDC's generally use gas from storage sites to serve customer needs directly, whereas intrastate pipeline companies use underground storage for operational balancing and system supply as well as the energy needs of end-use customers. While most LDC and intrastate pipeline storage operations are subject only to State regulatory agencies, a few (8 out of 59) are subject to FERC jurisdiction because they also provide significant service to the interstate market. LDC's are highly dependent upon underground storage because they must be ready to serve their residential and other firm customers with supplies at all times, especially during periods of winter peak demand. Without access to market area storage, LDC's must contract for more capacity on their supplying pipelines than would otherwise be the case, thus incurring large charges (reservation fees) based upon maximum peak-day demand.

- **Independent operators** own or operate about 3 percent of working gas capacity. Many of the salt cavern and high-deliverability sites currently being developed have been initiated by independent storage service operators. If the independent operators principally serve the interstate market, they are subject to FERC regulations; otherwise, they are State regulated. Several independent storage operations are joint ventures that include major interstate pipeline companies and LDC's as partners, or they are subsidiaries of interstate pipeline companies operating as independent entities.

The lower inventories and increased injection and withdrawal activities throughout the year may indicate a more fundamental adjustment relating to the economics of storage use and a reassessment of what storage levels are adequate for supply reliability. For example, despite the lowest levels of working gas since 1978 going into the last heating season, storage performed well in meeting the extraordinary demands placed on the system during January 1994. As some storage services have become unbundled, it is likely that users of storage have become more cost conscious and have begun to evaluate more closely their use of storage relative to their needs and purchasing strategies.

The Emphasis on Salt Cavern and Other High-Deliverability Storage

Another new characteristic of the storage market is the increasing reliance on salt cavern storage. Most salt cavern facilities are designed with the intent of cycling the entire working gas capacity 5 to 10 times each year. Typical injection periods are in the range of 20 days. In contrast, more traditional storage, such as storage in depleted reservoirs, is cycled only once each year and typically requires 200 days to refill.[55]

[55]For further information, see Thomas F. Barron, "Underground Storage of Natural Gas," *GasMart 1993* (Kansas City, MO, March 8, 1993).

Table 8. Working Gas Storage Capacity and Daily Deliverability, by Type of Site and Operation, As of December 31, 1993

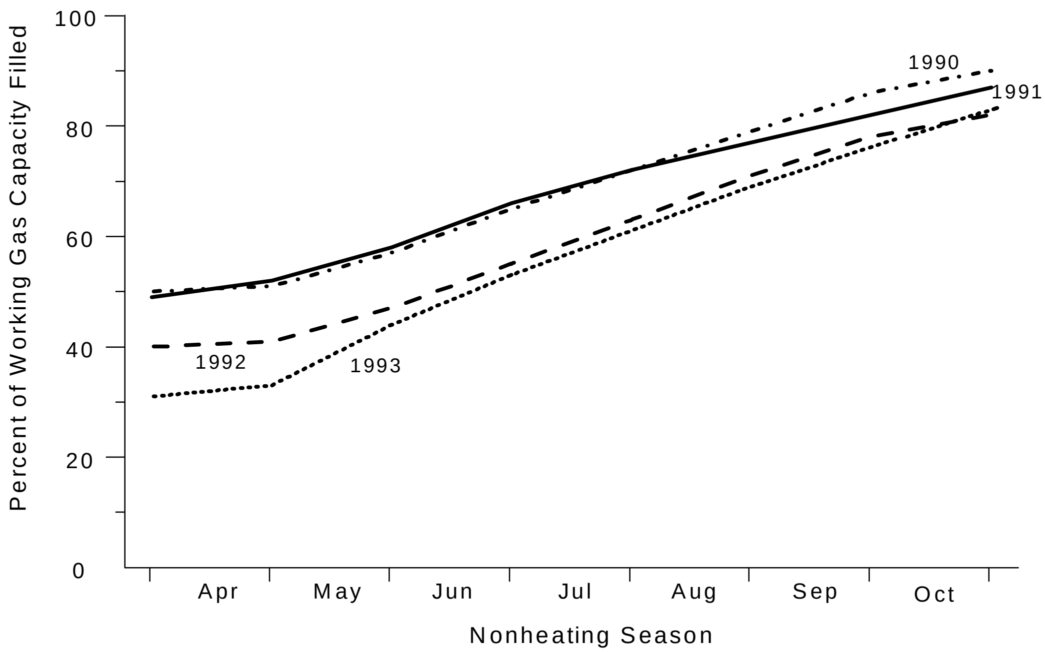
Type and (Number) of Operators	Depleted Gas/Oil Fields			Aquifers			Salt Cavern			Total				
	Number of Fields	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	Number of Fields	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	Number of Fields	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	Number of Fields	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	Percent of Working Gas (Bcf)	Percent of Daily Deliver-ability (MMcf/d)
Under FERC Jurisdiction														
Interstate Pipelines(27) ..	180	2,098	29,336	13	164	2,303	3	20	2,196	196	2,282	33,834	61	51
LDC's (9)	31	349	5,119	1	15	525	1	7	597	33	371	6,241	10	10
Independents (4) .	3	48	643	0	0	0	1	2	19	4	50	662	1	1
Total (40)	214	2,495	35,098	14	179	2,828	5	29	2,811	233	2,703	40,737	72	62
Nonjurisdictional														
LDC's and Intrastate Pipelines (52) .	119	696	16,773	25	269	4,528	6	20	1,661	150	985	22,962	26	35
Independents (11)	8	52	1,044	0	0	0	5	14	1,200	13	66	2,244	2	3
Total (63)	127	748	17,817	25	269	4,528	11	34	2,861	163	1,051	25,206	28	38
Total														
Interstate .... Pipelines(27) ...	180	2,098	29,336	13	164	2,303	3	20	2,195	196	2,282	33,835	61	51
LDC's (61)	150	1,045	21,892	26	284	5,053	7	27	2,258	183	1,356	29,203	36	44
Independents (15)	11	100	1,687	0	0	0	6	16	1,219	17	116	2,906	3	4
Total (103)	341	3,243	52,915	39	448	7,356	16	63	5,672	396	3,754	65,944	100	100

Bcf = Billion cubic feet. MMcf/d = Million cubic feet per day. LDC's = Local distribution companies.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, EIA-191 "Underground Gas Storage Report."

While salt cavern storage accounts for only 2 percent of total working gas capacity, it can provide 9 percent of available storage deliverability on a peak day. In 1993, there were 16 active salt cavern sites, 9 of which had been developed since 1986. This type of storage provides a great deal of flexibility for quick withdrawals and refills. For example, during Hurricane Andrew, one salt dome storage facility (Hattiesburg Gas Storage in Mississippi) was called upon to withdraw more than 60 percent of its working gas capacity in 3 days, with refilling occurring over the next few weeks. Because of its ability to cycle the gas quickly, salt cavern storage is very useful for supporting the increased load-balancing requirements of the industry, the new generation requirements for combined-cycle plants, and as supply for no-notice service.

Withdrawals from salt cavern storage account for an increasing percentage of monthly storage withdrawals, particularly during the nonheating season (Figure 24). Although withdrawals from salt cavern storage represented less than 4 percent of total withdrawals during each of the heating seasons from 1989 to 1993, they accounted for 9 percent in the 1993 nonheating season (while most reservoir storage is in the injection cycle). Many of today's salt cavern storage customers are electric utilities, who are increasingly using high-deliverability storage for very short-term peaking purposes. Depending on summer temperatures and thus electric generation needs, utilities may cycle their own storage inventory many times in the summer months. From 1988 through 1993, for instance, monthly withdrawals from salt storage sites, as a percentage of withdrawals from all other storage sites, ranged from a low of 1 percent in December to a high of nearly 10 percent in June (Figure 25).

Figure 22. Working Gas Levels as a Percentage of Working Gas Capacity During Nonheating Seasons, 1990-1993



Sources: **1990:** Energy Information Administration, EIA-191/FERC-8, "Underground Gas Storage Report"; **1991 - 1993:** Energy Information Administration, EIA-191, "Underground Gas Storage Report."

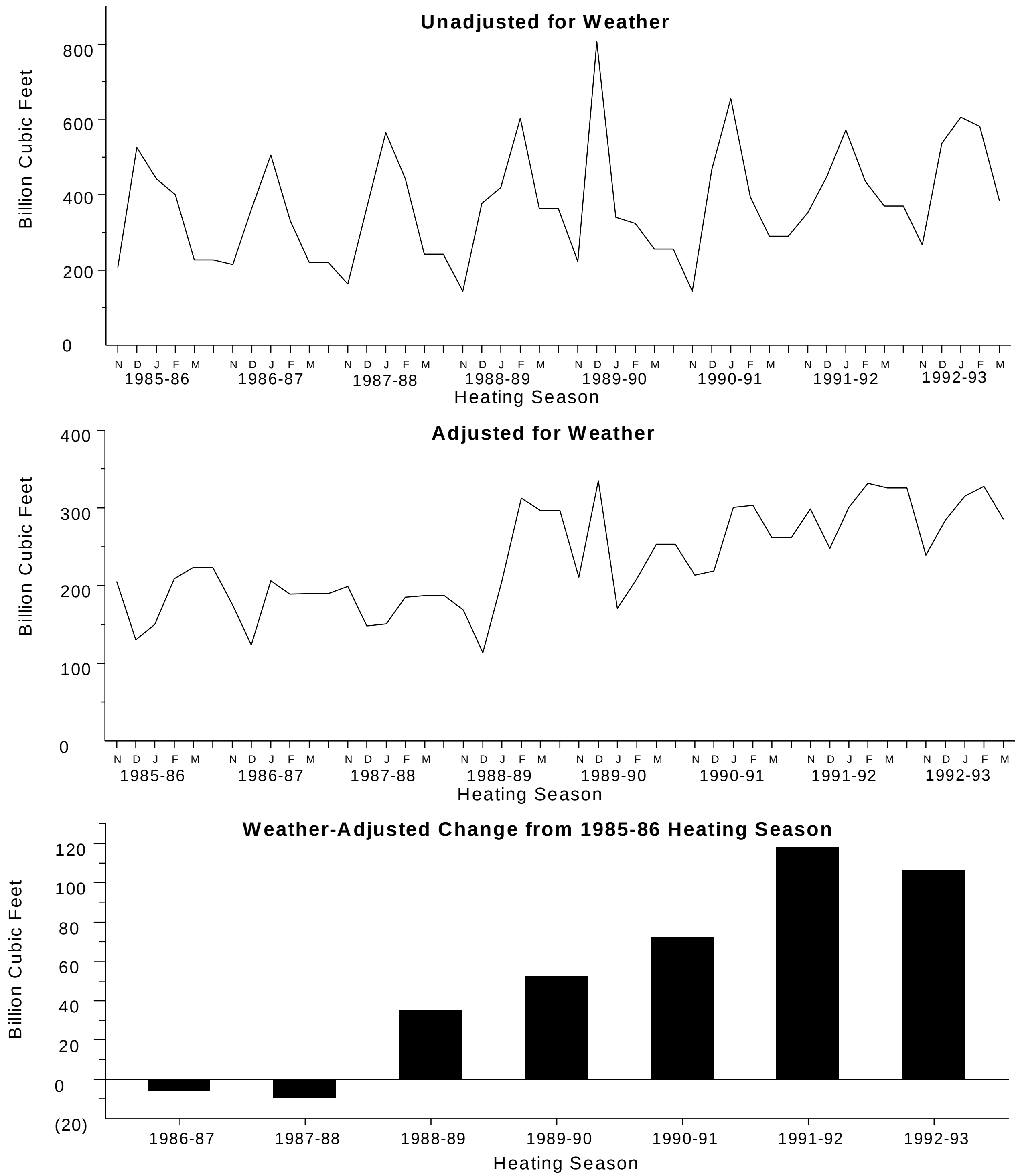
Table 9. Monthly Natural Gas Injections, Withdrawals, and Working Gas Levels, Heating Years 1983-87 Versus 1988-92
(Volume in Million Cubic Feet)

Month	Average Injections (per field)				Average Withdrawals (per field)				Average Working Gas (per field)			
	Period 1983-87	Period 1988-92	Volume Change	Percent Change	Period 1983-87	Period 1988-92	Volume Change	Percent Change	Period 1983-87	Period 1988-92	Volume Change	Percent Change
Nonheating Season												
April	380	474	94	25	259	311	52	20	4,803	4,683	-120	-2
May	679	796	117	17	89	119	30	34	5,392	5,324	-68	-1
June	717	853	136	19	66	83	17	26	6,025	6,074	49	1
July	753	849	96	13	80	110	30	38	6,672	6,780	108	2
August	708	828	120	17	90	127	37	41	7,283	7,464	181	2
September	669	801	132	20	64	122	58	91	7,887	8,144	257	3
October	492	594	102	21	160	217	57	36	8,211	8,523	312	4
Nonheating Season Monthly Average	628	742	114	18	115	156	41	36	6,610	6,713	103	2
Heating Season												
November	230	310	80	35	496	585	89	18	7,932	8,230	298	4
December	139	191	52	37	1,122	1,366	244	22	7,023	7,094	71	1
January	116	190	74	64	1,420	1,352	-68	-5	5,678	5,862	184	3
February	132	153	21	16	997	1,219	222	22	4,836	4,829	-7	0
March	243	267	24	10	656	867	211	32	4,441	4,269	-172	-4
Heating Season Monthly Average	172	222	50	29	938	1,078	140	15	5,982	6,057	75	1
Heating Year Monthly Average	438	526	88	20	458	539	81	18	6,348	6,442	94	1

Note: A heating year is from April of one year through March of the next year; for example, April 1983 through March 1984 is the 1983-84 heating year. Data are not adjusted for weather. Totals may not equal sum of components because of independent rounding.

Sources: **April 1983-1990:** Energy Information Administration, EIA-191/FERC-8, "Underground Gas Storage Report"; **1991 - March 1993:** Energy Information Administration, EIA-191, "Underground Gas Storage Report."

Figure 23. Withdrawals from Underground Natural Gas Storage During Heating Seasons, 1985-86 Through 1992-93



Note: Because vertical scales differ, graphs should not be directly compared. Monthly withdrawals have been adjusted for weather by subtracting the estimated influence of heating degree days from withdrawals. The estimated influence is obtained by regressing withdrawals on heating degree days.

Sources: **1985-86 through 1990-91:** Energy Information Administration, EIA-191/FERC-8, "Underground Gas Storage Report"; **1991-92 through 1992-93:** Energy Information Administration, EIA-191, "Underground Gas Storage Report"; **Heating Degree Days:** National Oceanic and Atmoshperic Administration.

Although pipeline companies are not the major participants in salt cavern projects, they are beginning to find these storage sites ideal to support their increased load-balancing requirements as well as to provide a backup source for meeting their no-notice service requirements. In general, storage used for no-notice transportation service must be located fairly close to consumers as it must be available quickly. The salt caverns on the Gulf Coast are probably somewhat remote to support this service directly, for instance, to customers in the Northeast and Midwest regions in the winter. But in Texas and Louisiana, these facilities are well situated for serving such customers as electric utilities during summer peak usage periods.

Although its role is clearly increasing, salt cavern storage facilities have limited working gas volume and are still being used primarily for peaking operations. During 1991, salt cavern storage averaged 0.77 cycles. Thus, one of its major advantages, that is, its potential for multiple cycling during the year, has yet to be exploited.[56] One possible explanation for the limited use of salt storage lies in the rate structure under which the storage service has been offered. Most pre-Order 636 salt cavern storage remains subject to rate-based cost recovery pricing. Thus, storage operators generally have been able to obtain their regulated rate of return on storage operations without multiple cycling of the facility. Peaking service is a high-cost service, and in this role, salt storage competes with other high-cost supplemental sources. In the future, salt storage, as well as other high-deliverability storage facilities, will increasingly operate under market-based rates and require higher volume usage to remain competitive. Many proposals for new storage facilities include the use of market-based rates. As of December 1993, FERC had already approved market-based storage rates for three storage operators, Richfield Gas Storage System (Kansas), Petal Gas Storage Company (Mississippi), and Transok Inc. (Oklahoma).

New Market Requirements Are Driving Storage Expansions

Underground storage in the United States has historically served a variety of operational needs for pipeline companies, producers, distributors, and end users. One of the primary uses has been to enhance the seasonal deliverability of mainline transmission capacity.[57] In the market areas, storage also serves as a backup form of supply in the event of an interruption in wellhead production (i.e., as a result of a hurricane or well freezeup). In production areas, other uses of underground storage include load balancing of the daily throughput on pipelines in order to prevent operational problems associated with high or low levels of line pack, levelizing wellhead production, and, more recently, hedging seasonal differences in wellhead prices.

Traditionally, these services or applications for underground storage have been met through the use of baseload storage facilities. These facilities have been developed primarily in depleted gas and oil fields, with large working gas capacities and relatively long (60 to 100 days) withdrawal cycles. Most have been designed with injection cycles in the range of 200 days with the intent of refilling storage during the summer months. Pipeline capacity was generally constructed along with new storage capacity in order to assure adequate downstream deliverability of the storage gas during the peak winter periods. Much of the existing storage capacity in the United States, particularly in the major market areas of the Northeast and Midwest, was designed and built by interstate pipeline companies for such service.

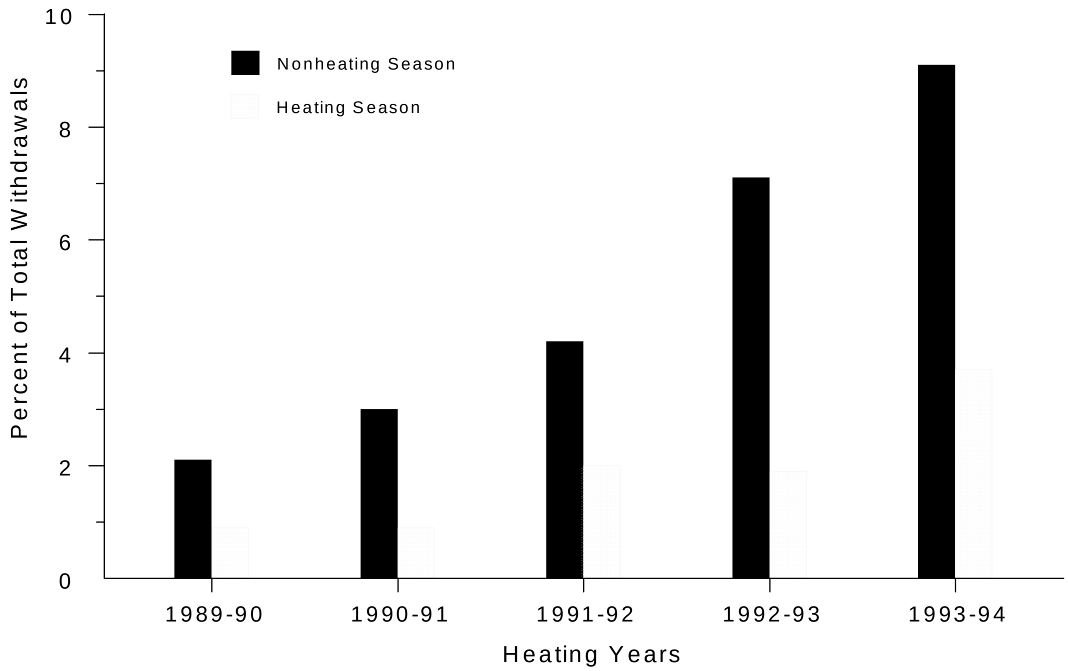
Order 636 and significant new developments in supply and demand conditions have required market participants to explore new approaches to the use of storage facilities, develop new services, and propose substantial additions to existing storage capacity. Although additions to underground storage capacity for the traditional services previously described continue to be proposed, a substantial portion of the proposed additions have very different characteristics. These include:

- Shorter withdrawal periods, in the range of 10 to 15 days (as in the case of the substantial number of proposed salt cavern facilities)
- Concentration of projects in the Gulf Coast producing region
- Limited plans to construct pipeline capacity along with the new storage capacity

[56]Other (nonsalt) high-deliverability sites, in fact, cycle their inventories more often than salt cavern storage (1.18 cycles versus 0.77 cycles, respectively, in 1991). Of the 378 underground natural gas storage sites active in 1993, 33 nonsalt cavern sites were classified as high-deliverability sites, based on the ability to withdraw all working gas in 20 days or less.

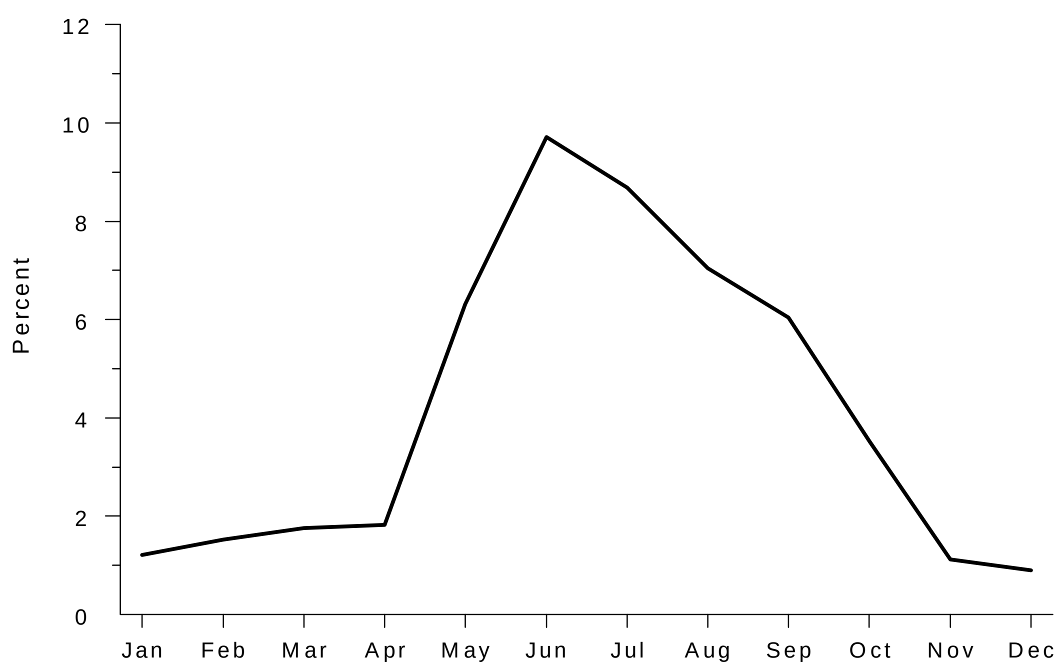
[57]In this form, underground storage located in or near the market area acts as an incremental supply source that serves as an alternative to building mainline transmission capacity to meet peak winter demands. As such, an interstate pipeline company can size the longest portion of its mainline capacity (that between the producing regions and underground storage located closer to its major market areas) at its annual-average throughput rate; transmission capacity sized to meet the much larger peak winter demands need be built only between the storage fields and the customer.

Figure 24. Salt Cavern Withdrawals as a Share of Total Natural Gas Storage Withdrawals, Heating Years 1989-1993



Sources: **April 1989-1990:** Energy Information Administration, EIA-191/FERC-8, "Underground Gas Storage Report"; **1991 - March 1994:** Energy Information Administration, EIA-191, "Underground Gas Storage Report."

Figure 25. Salt Cavern Withdrawals as a Share of All Other Withdrawals (Average for the Years 1989-1993)



Sources: **1988-1990:** Energy Information Administration, EIA-191/FERC-8, "Underground Gas Storage Report"; **1991-1992:** Energy Information Administration, EIA-191, "Underground Gas Storage Report."

- Sponsorship by independent developers rather than interstate pipeline companies

- Year-round capability for withdrawal and injection

- Little or no notice required for injection or withdrawal.

The prevalence of these nontraditional characteristics is the result of increasing demands for new services by storage customers. Order 636 is a significant factor behind these changes. However, there are also significant changes in market conditions that are adding to the need for new services.

- **New business relationships.** Order 636 is changing the structure of business relationships and the contractual practices within the gas industry. The order's provisions for unbundling, no-notice sales service, and rate design are most important for underground storage. In particular, much of the new storage being proposed by third party developers is intended to offer storage services previously provided as part of pipeline bundled sales services, such as supply balancing, no-notice, and emergency supply backup service.

- **Growth in seasonal demand.** Since 1989, end-use consumption of natural gas during the heating season has grown steadily, increasing by 4 percent in the 1992-93 heating season alone. Storage activity has grown in tandem, even after adjusting for weather variations.[58]

- **Decline in surplus production capacity.** For much of the past decade, gas purchasers could rely on surplus wellhead gas production capacity from producing fields in the Gulf Coast to meet short-term changes in gas demand and as a form of backup supply. However, this surplus productive capacity has declined, allowing underground storage in the production area and in the market area to play an increasingly important role in meeting short-term swings in demand and in enhancing reliability of supply.

- **Growth in new markets.** During the next 10 to 20 years, significant growth in natural gas demand is expected to occur from new gas-fired electric power plants using simple cycle or combined-cycle gas turbines.[59] The units are designed to meet highly variable electric power generation needs and will require significant surge capacity to accommodate quick on-and-off cycles. Underground storage with rapid injection and withdrawal capabilities and located near electric power plants will be one means of meeting such surge requirements.

These market trends have a major impact on the types of storage services consumers are demanding. Thus, in addition to traditional seasonal storage services, consumers are also interested in underground storage for:

- **Supply balancing**—the daily and/or monthly reconciliation of nominations and deliveries between buyers and sellers of gas

- **Emergency backup**—the use of storage as a backup source of supply in the event of a production failure or the nondelivery of gas

- **No-notice**—the firm delivery of the difference between a customer's daily nomination and what the customer actually required on that day

- **Price hedging**—the use of storage to hedge seasonal and/or monthly differentials in gas prices.

A common characteristic of these services is that they require significantly more operational flexibility than provided by underground storage used for traditional seasonal supply service. This includes such characteristics as the ability to inject and withdraw gas on a continuing basis throughout the year to balance daily or monthly demands and the ability to withdraw large quantities of gas quickly and reliably to meet surges in demand or replace lost production.

The offering of new services and their marketing in recent years is a radical change for underground storage (see box, p. 89). Greater numbers of storage operators are offering varied services, such as no-notice, swing, load balancing, and aggregation services, in addition to inventory service, to attract new customers and remain competitive. Major producing companies, such as Enron, Texaco, Shell, etc., as well as major pipeline companies, have spun off marketing subsidiaries, which are themselves either developing storage or setting up subsidiaries which are doing so. The major producers are securing storage facilities as a backup source of supply in the event of unanticipated field equipment problems, and more generally as a means of maintaining constant wellhead production.

[58]Energy Information Administration, "Expanding Role of Underground Storage," *Natural Gas Monthly*, DOE/EIA-0130(93/10) (Washington, DC, October 1993), p. 17.

[59]Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994), p. 33.

Underground Storage Services		
Service and Primary Users	**Nature of Service**	**Comment**
Seasonal Storage: Baseload and Peaking ● Pipeline companies ● Local distribution companies (LDC's)	● Seasonal load balancing in which storage replaces need for additional pipeline capacity (i.e., serves as an additional source of supply) ● Typically, long injection/withdrawal periods ● Used primarily in winter heating season	● Most existing storage designed for these uses ● Primarily developed by pipeline companies and LDC's
Pipeline System Balancing ● Pipeline companies	Balance daily throughput on pipeline to match receipts/ deliveries	● Under Order 636, service will be provided via operational flow orders and retained pipeline company storage
Supply Balancing ● Gas shippers, including - LDC's - Marketers - Pipeline companies	● Balance nominations and deliveries to pipelines ● Primarily end-of-the month activity, but can be weekly or daily	● Intended to avoid imbalance penalties ● Activity year-round
Emergency Backup ● Gas suppliers and consumers, including - Producers - LDC's - Marketers - Pipeline companies	● Backup source of gas in event of a production failure/nondelivery ● Short-term alternative supply source	● Market area and production area, storage can be used ● Increases reliability of supply
No-Notice ● Pipeline companies ● LDC's	● After-the-fact nomination of gas to replace unanticipated/ unnominated consumption	● Pipeline companies required to provide service under Order 636
Price Hedging ● All	● Hedge of seasonal/monthly price differentials	● Not primary driver behind recent growth

Source: Energy and Environmental Analysis Inc., *Development Cost of New Underground Natural Gas Storage Facilities in the Lower-48 United States*, February 1994.

In assuming the supply aggregation role previously played by the interstate pipeline companies, marketers are beginning to use storage as a means of building inventories from which to serve their customers and meet sales contracts requirements. Their aim is to obtain greater operational flexibility and the inventory space to balance their purchasing opportunities with the demand requirements of their customers, as well as the opportunity to market storage space that exceeds their own needs. Independent storage companies, in particular, have been entering the storage market in unprecedented numbers. Most are developing or proposing new salt cavern or other high-deliverability storage that offer the operational flexibility to support the new types of services being marketed.

Storage Development Geared to the New Market

These new service requirements and growth in demand are behind the surge of interest in new underground gas storage construction. Through February 1994, 77 separate phases of proposed new storage fields (45) and expansion projects (32) had been announced with startup dates within the decade (Table 10). If all phases of these projects were built, a total of 448 billion cubic feet (Bcf) of new working gas capacity and 18.0 Bcf per day of peak withdrawal capacity would be added to existing storage capacity in the United States. This would represent a 12-percent increase (from 3,754 Bcf to 4,201 Bcf) in working gas capacity and a 27-percent increase in withdrawal capacity.

Types of Storage

Most new storage is being planned with access to multiple pipelines, that is, around market (pooling) hubs, a major consideration. The strategic placement of new storage sites in the vicinity of, or with ready access to, multiple pipeline transporters around market hubs also enables new operators to compete effectively with traditional storage operators. Of the 45 new storage projects, about 20 are located in areas near or adjacent to what have become known as market pooling points or have been proposed as such.

Developers see a variety of roles for underground storage located at or near a hub. Key services include load balancing and system supply for emergency backup. Conceptually, a combined storage and hub facility would act as a mini-pipeline system that transfers gas between sellers and buyers and balances daily fluctuations in deliveries to meet nominated volumes on the long-distance pipelines. Several developers also envision providing "value-added" sales services to prospective buyers, such as "swing services." These involve a gas supply contract that permits the purchaser to take gas at variable rates below the contract demand to match daily and seasonal swings in demands. In this sense, storage serves as an operational risk management tool that is essential if the producer or marketer plans to compete as a firm supplier of gas in the unbundled market.

Storage is also being marketed by some operators as a potential price arbitrage and futures trading hedging tool. More recently, the use of storage for price hedging has been less attractive. Tightening wellhead supply and an increased willingness by customers to utilize gas placed in storage in lieu of wellhead purchases have narrowed price differentials between seasons. Spot market prices in 1992 and 1993 were actually higher during the summer than much of the winter. As a result, opportunities for reducing annual gas supply costs vis-a-vis the use of seasonal storage have diminished. Many industry representatives argue that price hedging will not be a major driver of storage demand in the future.

Cost of New Underground Storage

The estimated capital cost for the 77 proposed storage projects is approximately $2.2 billion (Table 10), which represents a significant capital investment of about $367 million annually through 1999. By comparison, in 1991 interstate pipeline companies expended only $118 million on additions to underground storage facilities while reporting a total (undepreciated) value of underground storage plant in service of $2.7 billion for the year.[60]

To put these costs in perspective, it is useful to relate them to the changes in capacity and the potential costs to the consumer. Two measures are presented: capital costs and annual cost of service.[61]

Although each type of underground storage site has its own physical characteristics and economics (site preparation,

[60] Energy Information Administration, *Statistics of Interstate Natural Gas Pipeline Companies, 1991*, DOE/EIA-0145(91) (Washington, DC, December 1992), Tables 10 and 27. Companies filing the FERC Form 2, "Annual Report of Major Natural Gas Companies," represent the large majority of interstate gas transmission and storage activity in the United States.

[61] The underlying costs discussed in this section are based on and available in a report prepared for EIA by Energy and Environmental Analysis Inc., *Development Cost of New Underground Natural Gas Storage Facilities in the Lower-48 United States* (Washington, DC, February 1994). The annual cost of service is based on the following parameters: (1) capitalization and cost of capital based on 60-percent debt at 10 percent, 40-percent equity at 13 percent (weighted average 11.2 percent); (2) total Federal plus State tax rate of 37.3 percent; (3) depreciation based on useful life of 20 years; and (4) levelization of estimated annual cost of service over 20 years. The total annualized revenue requirement (annual cost of service) for a storage field under these assumptions is about 19 percent of the initial capital investment (initial rate base).

Table 10. Proposed New and Expansion Underground Storage Projects in the United States,1994-1999

Type of Project	Number of Projects			Additions to Base Gas Capacity (Bcf)	Additions to Working Gas Capacity (Bcf)	Total Additions to Storage Capacity (Bcf)	Additions to Withdrawal Capacity (MMcf/d)	Additions to Injection Capacity (MMcf/d)	Estimated Development Cost (Million $)
	New	Expan-sion	Total						
Depleted Fields	25	7	32	269	294	564	5,267	2,602	1,159
Aquifers	2	3	5	24	19	44	190	85	91
Salt Caverns[a]									
Salt Domes	--	--	25	43	100	144	9,700	2,915	690
Salt Beds	--	--	15	16	34	50	2,800	1,390	271
Total Salt Formations	18	22	40	59	134	194	12,500	4,305	961
Total Projects[b]	45	32	77	354	448	802	17,957	6,992	2,213

[a]Salt cavern storage is prepared by injecting water (leaching) into a salt formation (either a salt bed or salt dome) and shaping a cavern. Salt beds are more expensive to develop than salt domes because in general they are thinner formations (about 1,000-feet thick vs. up to 30,000 feet), which makes them more susceptible to deterioration.

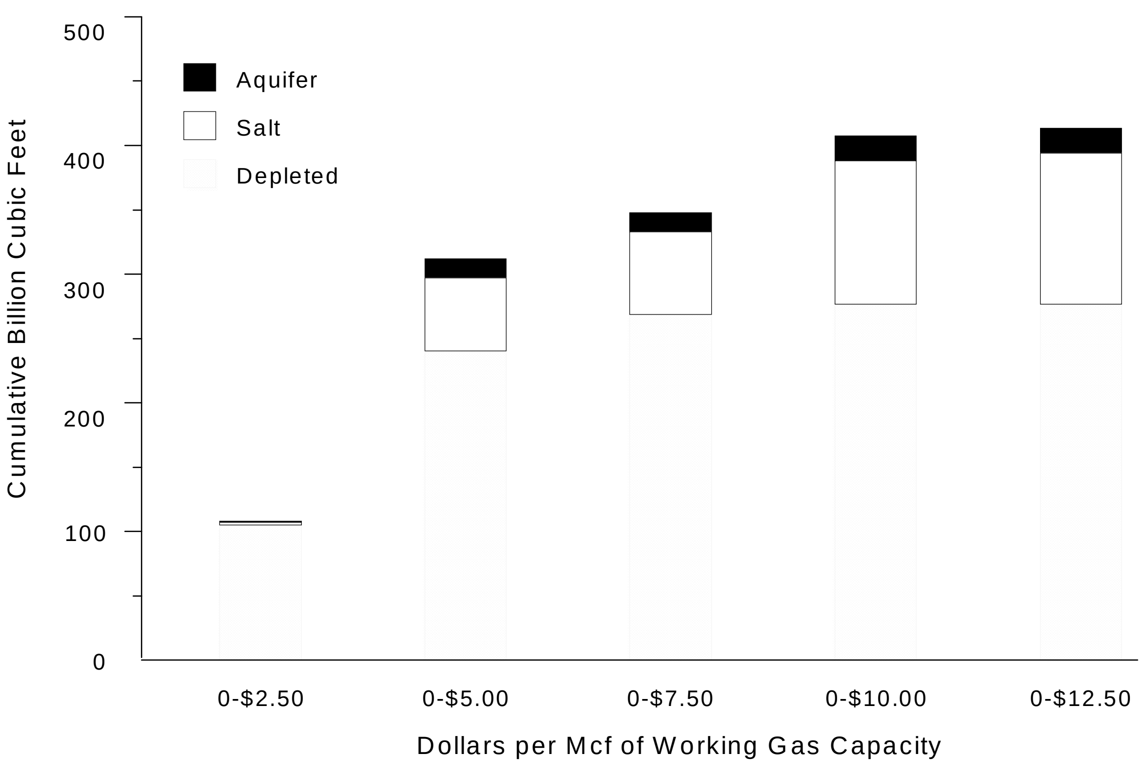
[b]Announced as of February 28, 1994.

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

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Office of Oil and Gas, "Proposed Natural Gas Storage Projects," data base as of March 1, 1994, based on Federal Energy Regulatory Commission filings and information from various industry news sources.

Figure 26. Projected Working Gas Capacity for New and Expansion Projects by Development Cost



Mcf = Thousand cubic feet.

Source: Energy Information Administration, Office of Oil and Gas, "Proposed Natural Gas Storage Projects," data base as of March 1, 1994, based on Federal Energy Regulatory Commission filings and information from various industry news sources.

deliverability rates, cycling capacity), a simple way to address these costs overall is to look at the required capital outlay per unit of additional working gas capacity. Industry uses a rule-of-thumb estimate of about $10 per Mcf of working gas capacity for new salt cavern construction and less than half that for new depleted field conversions. This is because expansion of an existing facility is generally less expensive than the initial development phase. Based on the estimated development costs of all 77 proposed storage projects, about 312 billion cubic feet (Bcf), or 70 percent, of new working gas capacity is expected to be developed for less than $5 per Mcf (Figure 26). Projects estimated to cost between $5 and $10 per Mcf, on the other hand, represent only an additional 96 Bcf of new working gas capacity, slightly more than 21 percent of the total 448 Bcf of proposed new working gas capacity.

While capital costs are a useful measure for comparing absolute costs, they cannot fully capture the effective annual cost per Mcf of storage service to the consumer. Thus, from the consumer's perspective, it is also necessary to look at the proposed rates for service. To address the impact on customers, a second measure was estimated—the levelized annual cost of service for each project expressed as a cost per Mcf of gas withdrawn based on varying assumptions of utilization of the field (the number of times its working gas capacity will be cycled, on average, during a 12-month period).[62]

If used for seasonal storage, most depleted and aquifer storage fields are cycled less than once per year. Within the scope of current expansion proposals, about 275 Bcf of working gas capacity could be added in depleted and aquifer fields at a cost of service of $0.75 per Mcf (Figure 27).[63] The 275 Bcf represents 61 percent of the proposed additions to working gas capacity, which would add about 7 percent to working gas capacity nationwide.[64]

Development costs for salt cavern storage are much higher than for other types of storage. Cost per unit of working gas capacity for salt cavern storage is roughly twice that of a comparable project using a depleted field or aquifer. As a result, salt storage is economically attractive only in applications that (1) offer a high value per unit of working gas capacity (i.e., backup service), (2) require multiple cycles per year (i.e., balancing), or (3) require high deliverability .

Based on estimated annual cost of service underlying the proposed salt cavern projects, roughly 25 Bcf of working gas capacity could be developed in salt cavern facilities at prices less than or equal to $0.75 per Mcf (Figure 27) if it were used only for seasonal storage (that is, one cycle per year). This is equivalent to less than 10 percent of the proposed working gas capacity to be made available in depleted fields and aquifers at this price (Figure 27).

If the proposed working gas capacity in depleted fields or aquifers could be cycled 1.5 times in a given season, the equivalent of an additional 450 Bcf of working gas capacity could be brought into service at prices comparable to $0.75 per Mcf.

In contrast, if the salt cavern projects are primarily developed to be used for services that generate multiple cycling in a given year, a significant amount of additional overall working gas capacity would come on line, and an even greater amount of working gas throughput (i.e., working gas capacity developed times the number of cycles in the year) would be available for prices less than $0.75 per Mcf. For example, the equivalent of roughly 125 Bcf of working gas throughput could be developed at prices less than $0.75 per Mcf if the proposed salt formation storage could be cycled at least twice a year; approximately 500 Bcf of throughput could be developed if the same working gas capacity could be cycled four times a year (Figure 27).

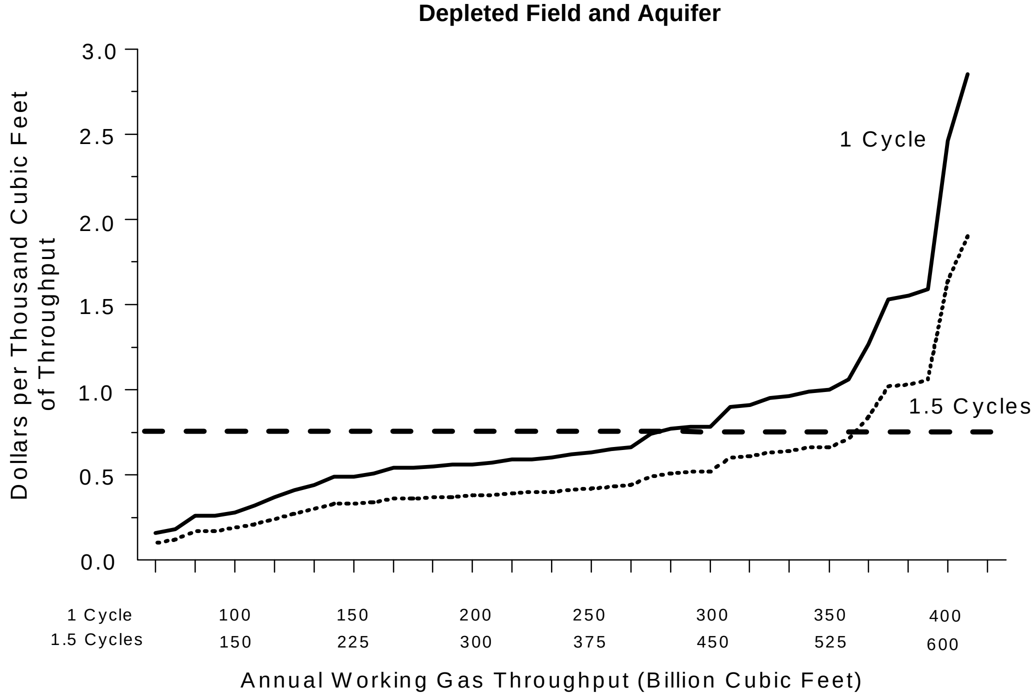
Although most proposed salt cavern facilities will be capable of cycling their working gas capacities up to 10 times in a given year, the actual degree of cycling and, consequently, the volume of working gas throughput provided by these facilities depend on the existence of markets that require multiple

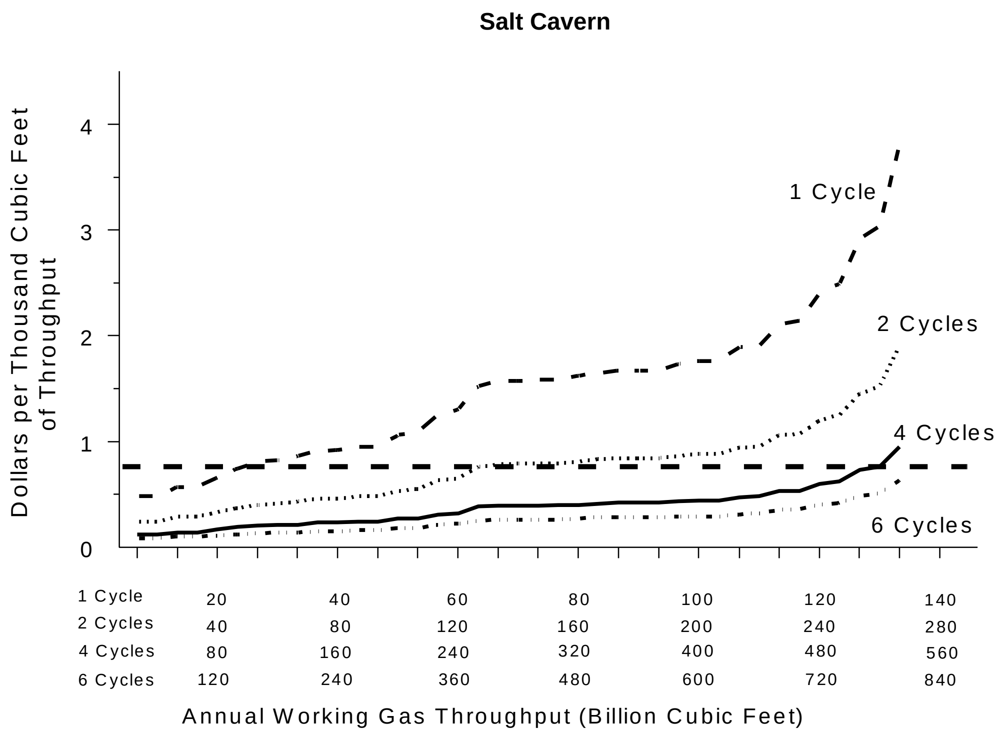
[62]A storage developer will recoup its investment in a storage project through the sale of services to its customers over a period of years. Rates for the sale of storage services depend on the construction and operating costs of the facility, its depreciation period, and the expected utilization of the facility. Rates may vary depending on the ratemaking practices of the responsible regultory authority.

[63]The $0.75 per thousand cubic feet (Mcf) estimate is a useful reference point for several reasons: (1) a range of $0.30 to $0.50 per Mcf is often used as the average cost of existing storage; (2) at 150 to 200 percent of this average cost, $0.75 per Mcf represents a reasonable marginal cost for new storage; (3) peak winter/summer price differences have recently been in the range of $0.75 per Mcf; and (4) current proposals indicate that there is not much interest in developing storage costing $1.00 per Mcf or more. Several of the proposed projects in depleted fields are being designed with greater flexibility than traditional depleted field storage, including the ability to cycle working gas capacities more than once in a given season; for instance, the Wild Goose project in California.

[64]Development costs for new depleted field storage facilities typically range from about $1 to $6 per thousand cubic feet (Mcf) of working gas capacity, with an average of roughly $4 per Mcf. The Wild Goose Project has an estimated initial development cost of about $15 per Mcf. While this seems high relative to other depleted fields, the facility is being designed as a high-deliverability, multiple cycling field along the lines of a salt dome. Multiple cycling reduces the effective per Mcf cost of service from the field, making it competitive with other depleted fields.

Figure 27. Estimated Annual Cost of Service for Proposed Storage Projects Under Several Cycling Scenarios





Note: Volumes for 1 cycle equal proposed additional working gas capacity; for multiple cycles, the volumes shown are the equivalent throughput possible from the working gas capacity.

Sources: Energy Information Administration (EIA), Office of Oil and Gas: derived from: **Cost of Service**—Energy and Environmental Analysis, Inc., *Development Cost of New Underground Natural Gas Storage Facilities in the Lower 48 United States*, Feburary 1994; and **Proposed Storage**—EIA, Office of Oil and Gas, "Proposed Natural Gas Storage Projects," data base as of March 1, 1994, based on Federal Energy Regulatory Commission filings and information from various industry news sources.

injections and withdrawals per year. Thus, developers have an incentive to offer numerous services to maximize their facility's utilization. Likewise, customers of these projects will have incentives to provide for multiple needs from a single field or project. Hence, it is not surprising that developers of salt cavern projects are proposing a variety of services that will use their sites to provide a number of different operational capabilities.

Regional Storage and Supplemental Supplies

The changes in the storage market brought on by FERC Order 636 are particularly reflected in the regional variability in current plans for new storage. The majority of new storage projects and the bulk of additional daily storage deliverability are slated to be developed in the supply areas of the Central, Southwest, and Southeast regions; areas where geology and the existing pipeline network coincide with the high-deliverability and "pooling" needs now required for system support. These regions have areas where salt cavern geology exists and numerous pipeline interconnects are already in place, which can readily support the pooling or "market hub" concept. For instance, the Central, Southeast, and Southwest regions account for 77 percent of the proposed additional storage deliverability through the rest of this decade; individually they represent increases of 29, 37, and 67 percent, respectively, above current levels of deliverability (Table 11).

These regions already have sufficient local production and storage facilities to handle existing needs (including some future growth in regional consumption). Thus, additions to new storage can be attributed to the potential need to support the requirements of customers in other regions, particularly the Northeast and Midwest, and to some extent the increased reliance on storage by supply-area pipelines for system management and by producers for managing their field production with their marketing requirements.[65] The fact that more than 77 percent of the planned deliverability capacity in these regions is from high-deliverability sites is another reflection of the greater development of storage in supply areas in support of the nonregional customer.

The level of proposed storage development in the Northeast and Midwest market areas is relatively small compared with planned increases in the supply regions (Figure 28). In the Northeast, the planned increase represents only a 15-percent growth in deliverability, while in the Midwest the increase is even less—only 2 percent. The Northeast and Midwest already have a large number of storage facilities that are highly integrated in the regional gas distribution networks. Further, in order to deal with wide variations in climate and a large residential market, the LDC's in the Northeast and Midwest maintain the largest and second-largest levels, respectively, of supplemental peaking capacity of the regions (Table 11). This capacity is provided by liquefied natural gas (LNG) and propane-air peaking facilities, which in the aggregate can supply more than 8.2 Bcf per day of short-term supplies to the regional networks, more than for all other regions combined.

Combined storage and LNG/propane peaking deliverability levels in the Northeast and Midwest regions (14.6 and 26.1 MMcf per day, respectively) are near to or exceed the average daily consumption during recent peak consumption months. (Regional production contributed little to local supplies during these same peak months.) Combined with the existing pipeline capacity feeding into the respective regions, the current regional infrastructure appears more than adequate to handle near-term seasonal needs. In recent years, very few additional peaking facilities have been installed in the two regions,[66] indicating that the existing level of peaking service is generally sufficient.

Most of the planned 31-percent increase in storage deliverability in the Western Region is to service the California market. The California market in some ways is a small-scale representation of the national market for storage. Like FERC, the California Public Utility Commission has restructured the intrastate market comparable to Order 636 restructuring, mandating unbundling of services and open access to transportation and storage services. As a result, the major intrastate pipeline companies and LDC's, as well as independent storage operators, see a need to develop additional storage, for many of the same reasons as in the interstate market.

In addition, however, storage facilities in the California market are being added to handle the increased flows of gas being imported into the State for enhanced-oil-recovery projects. Increased attention to environmental concerns in the State is expected to increase natural gas use in electricity generation and correspondingly increase the requirements for sufficient storage capacity, especially high-deliverability and peaking service. Currently, the region has 6.7 Bcf per day of storage delivery capability, which is about 62 percent of the pipeline capacity feeding into the region. This capacity together with LNG and propane-air peaking deliverability is about 95 percent of

[65] Although the Southeast Region has a moderate overall climate, LDC's in the region maintain a sizable peaking capacity. This is partly due to the lack of underground storage sites (actual and potential) in the region, particularly in the States along the mid-Atlantic corridor. Occasional extreme temperature changes, such as occurred in December 1989 and March 1993, make liquefied natural gas and propane supplemental supplies a critically important support mechanism in the Southeast Region.

[66] Gas Research Institute, "The Seasonal Demand and Supply of Natural Gas in the Lower-48 United States," GRI Report No. 92/0475.

Table 11. Regional Underground Storage and Peak-Shaving Capacity Relative to Pipeline Capacity and Peak Month Production/Consumption
(Volume in Million Cubic Feet per Day)

Region	Planned Additions to Deliverability from Underground Storage[a]	Current Regional Capabilities				Peak Month - Average[b]	
		Deliverability from Underground Storage 1993	LNG and Propane-Air Injection 1992	Total Supplemental	Pipeline Capacity (Net Entering the Region) 1993	Consumption	Marketed Production
Western	2,044	6,687	940	7,627	10,719	8,055	1,071
Southwest[c]	10,190	15,219	125	15,344	(32,421)	15,599	[d] 40,675
Central[c]	1,733	5,880	1,834	7,714	840	7,232	6,233
Midwest	400	22,384	3,755	26,139	15,777	18,765	919
Northeast	1,613	10,489	4,460	14,949	9,843	14,985	1,011
Southeast	1,977	5,284	1,913	7,197	4,847	6,704	1,411
Total	17,957	65,944	13,027	78,971	--	--	--

[a]Proposed additions 1993 through 1999.

[b]The volumes shown are the sum for the peak consumption month occuring since 1988, for the several States included in the respective region, divided by the number of days in that month.

[c]The Central and Southwest regions are net exporters of natural gas and, therefore, production levels and underground storage deliverability are not totally a reflection of regional requirements.

[d]This volume represents the average daily production that occurred in the Southwest Region during the periods of peak demand for the Midwest and Northeast regions, which are very dependent on the region to supply its winter requirements.

LNG = Liquefied natural gas.

Note: Totals may not equal sum of components because of independent rounding.

Sources: **Capacity:** Energy Information Administration (EIA), *Capacity and Service on the Interstate Natural Gas Pipeline System 1990*; **Underground Storage:** EIA-191/FERC-8, "Underground Storage Report"; **Planned Storage:** EIA, Office of Oil and Gas, "Proposed Natural Gas Storage Projects," data base as of March 1, 1994, based on Federal Energy Regulatory Commission filings and information from various industry news sources. **Consumption/Production:** EIA, *Natural Gas Monthly*, various issues. **LNG/Propane:** Gas Research Institute, *The Seasonal Demand and Delivery System for Natural Gas in the Lower-48 United States,* GRI Report No. 92/0475.

average-day consumption levels during recent peak months.

Overall, the ability of storage facilities to meet requirements during peak consumption periods in recent years indicates that—except in some isolated and localized situations—the current support infrastructure is adequate to meet current needs. Assuming that the expected growth rate of 1 percent per year in gas consumption from 1992 through 2010[67] is reasonable, the proposed growth in storage capacity is aimed toward satisfying a new market with new service requirements developing under Order 636.

Outlook

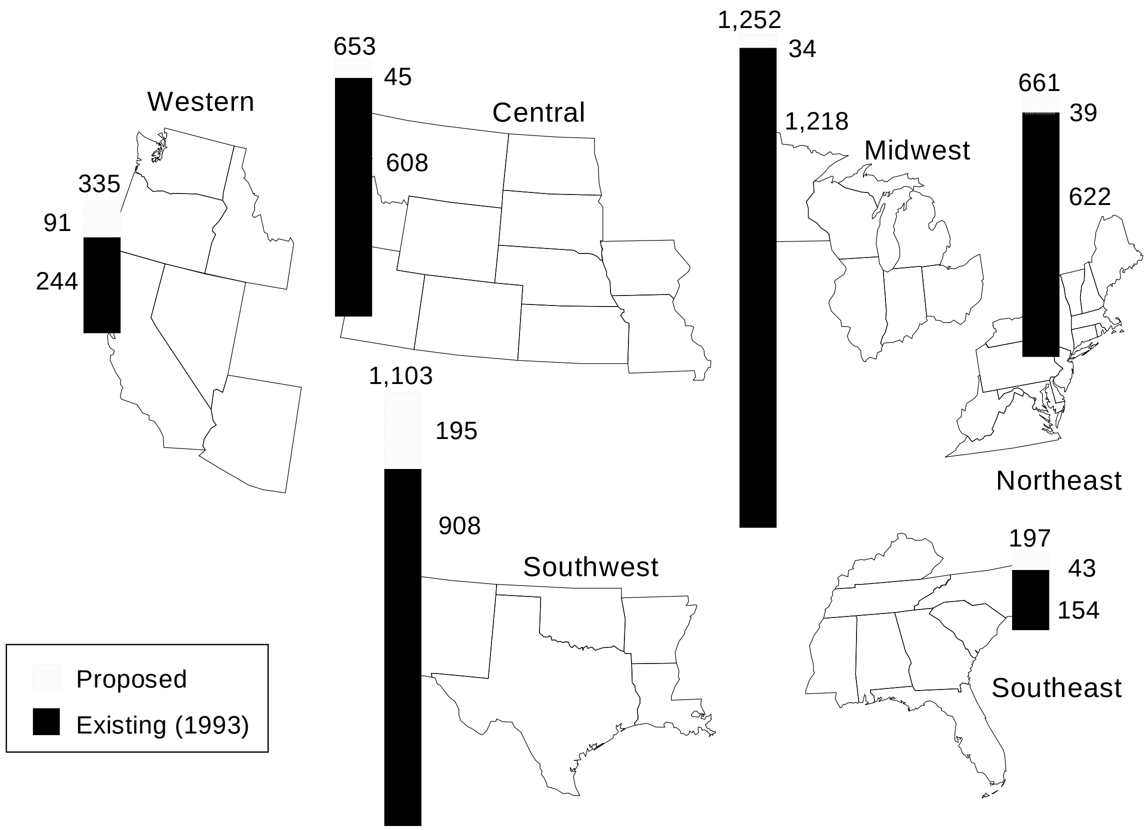
The industry has completed the first heating season under Order 636, tested by the extreme weather conditions in January 1994 with record storage withdrawals. As a result of Order 636, underground storage services have become much more important in the daily business operations of producers, marketers, industrial users, electric utilities, and even large residential users of natural gas.

The use of electronic bulletin boards (EBB's), in conjunction with storage capacity brokering, will allow transportation customers to conduct their daily business operations more efficiently. As these tools become more integrated into the market, inventory management will become more focused with the result that available storage may be used more effectively.

The use of working gas capacity will probably continue to change as the natural gas industry adjusts to operating under Order 636 and countervailing forces emerge. In this same

[67]Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994), p. 70.

Figure 28. Working Gas Capacity by Region, 1993 and Proposed Additions, 1994-1999
(Billion Cubic Feet)



Sources: **1993:** Energy Information Administration, EIA-191, "Underground Gas Storage Report"; **1994-1999:** Energy Information Administration, Office of Oil and Gas, "Proposed Natural Gas Storage Projects," data base based on Federal Energy Regulatory Commission filings and information from various industry news sources.

context, some of the currently planned storage development will probably be scaled back or canceled, especially those projects scheduled for completion beyond 1995. Developers will have a better opportunity to evaluate the feasibility of each project in the light of new market trends that will develop in the next several years. As working gas capacity usage levels have fallen, more capacity has become available to nontraditional customers, which may reduce the need for new capacity. The concentration of high-deliverability storage development is expected to continue. The increased transportation transactions in recent years combined with projected increases in overall demand for natural gas through the end of the decade, especially in the areas demanding flexibility in supply (e.g., electric generation), make it almost certain that high-deliverability storage will continue to dominate new site development. LDC's will increasingly need storage (owned or leased) to lower their costs as they attempt to compete in a more competitive and cost-conscious marketplace.

5. Financial Aspects of the Natural Gas Industry

Introduction

One of the most important factors affecting the financial performance of the natural gas industry during the past 15 years has been the changing nature of regulations and legislation. The Natural Gas Wellhead Decontrol Act of 1989 and the Federal Energy Regulatory Commission (FERC) Orders 380, 436, 500, and 636 have had a profound effect on the finances of the entire industry. They have also led to new institutional structures such as market hubs, futures and options markets, secondary markets for pipeline capacity rights, and, in some cases, highly competitive markets for certain types of gas services. This regulatory evolution has resulted in more competition and changing risks and rewards for the industry.

While gas producers continue to face competition from low-cost oil, their financial prospects are generally better now than at any time since the oil price collapse of 1986. The decline in oil and gas prices in the late 1980's forced producers to cut costs, reduce debt, and improve efficiency. The industry is now able to develop and add new reserves at about a quarter of the cost of a decade ago. Increases in production during the past 8 years, coupled with recent significant increases in the wellhead price of gas, have improved the revenue stream. With the decline in surplus productive capacity, producers are less burdened by the high costs of maintaining idle capacity. Favorable rate changes under Order 636 and improved access to the pipeline grid have also contributed to the producers' improving financial performance.

The development of the gas marketing industry was a direct outgrowth of open access regulation instituted in the mid-1980's, which created demand for repackaged gas services. Order 636 presents marketers with even greater opportunities to "rebundle" gas services because of the wider array of services to rebundle and the equal access to storage and transportation facilities. To remain competitive, many marketers have had to purchase or team with other pipeline, marketing, or production companies to offer services effectively. Throughout 1993, there was widespread consolidation. With many of these structural changes behind them, the remaining marketing companies will have greater prospects for revenue and earnings growth.

During the past decade, interstate pipeline companies had to adjust to regulatory efforts to increase competition in the purchase, transport, and sale of natural gas. Like the producers, this increased competition has led pipeline companies to streamline their operations and improve productivity. While Order 636 has required pipeline companies to alter their operations drastically, many aspects of the order are advantageous to pipeline companies in the short term. Over the longer term, the pipeline companies will face increasing competition for customers.

Local distribution companies (LDC's) face greater uncertainty under the market changes required by Order 636. With increasing responsibilities for the acquisition and management of supply and transportation services, LDC's now have the opportunity to manage these costs more effectively. But, many of the costs associated with gas industry restructuring are being passed through to them. The reaction of State regulatory authorities to these costs and to the purchasing strategies of the LDC's in the new market structure is uncertain. The financial outlook for LDC's is good if they can earn rates of return commensurate with their new added responsibilities and add new customers through competitive pricing and the introduction of new services.

This chapter examines the key factors affecting the financial performance of each segment of the natural gas industry between 1985 and 1993. It develops several measures of financial performance and compares them across industry segments and within individual segments. The first part of the chapter presents a cross-cutting picture of financial performance by comparing indices for each segment with the Standard and Poor's (S&P) 500 market average.[68] It then describes the influences on individual segments of the industry. Although some historical context is given, the section highlights the major financial influences in 1993. In addition, the chapter describes the issues that are most likely to affect the financial picture of the industry during the next few years.

There are several approaches to assess the financial performance of the different segments of the natural gas industry, including evaluation of debt levels, profitability, and market valuation (see box, p. 99). The analysis in this chapter uses data for a sample of publicly traded companies. The producer segment was divided between major and independent producers. The interstate pipeline industry was examined both

[68]The S&P 500 is a well-recognized data base that includes 500 of the largest U.S. industrial companies. Financial ratios for the S&P 500 presented in this chapter may differ from those appearing in Standard and Poor's publications. The methodology employed within this analysis is based upon simple aggregation of the S&P 500 companies' data, whereas Standard and Poor's published ratios are based on market valuation weighting factors.

including and excluding Columbia Gas System, which filed for bankruptcy protection under Chapter 11 in 1991.[69] The LDC's were initially divided between gas-only companies and combination gas and electric companies. However, the combination-service LDC's were excluded from the analysis because their financial measures were not substantially different from the gas-related LDC's.

Among the companies selected for this analysis, there is some overlap in operations. For example, some companies, such as Consolidated Natural Gas Company, are vertically integrated with both substantial transmission and distribution arms. Because of difficulties in separating costs between functions, the companies were placed in the segment that represented the largest share of their revenues. Finally, adequate data for the marketer/aggregator segment of the industry were not available for comparison. Most marketing firms are privately held companies whose financial records are not publicly available.

Overall Financial Performance of the Industry

In 1993, several indicators pointed to improved performance for the natural gas industry. This overall improvement follows a decade in which the performance of the different segments varied greatly, in part because of the differing impacts of regulatory changes. Financial performance in the gas industry since 1985 has been driven by two sets of influences. Broad, cross-cutting factors such as fluctuations in interest rates, changes in weather, and swings in gas prices have affected the financial outlook for all segments. Other factors, though, have altered the financial picture for the individual segments in unique ways. For example, the Alternative Minimum Tax primarily affects producers. Some of the major factors affecting the finances, directly or indirectly, of all industry segments since 1985 are listed below.

Environmental and Energy Policy. A number of recent energy and environmental initiatives have been undertaken that should boost the use of natural gas (see Appendix A). Environmental initiatives, such as the Clean Air Act and the Clinton Administration's commitment to reduce greenhouse gas emissions to 1990 levels by 2000, should favor continued growth throughout the gas industry. Moreover, energy policy directives such as Order 636, the Domestic Natural Gas and Oil Initiative, and the Energy Policy Act of 1992 were all meant, in part, to expand the use of natural gas.

Oil and Gas Prices. Because of the extensive dual-fired capacity in the United States, oil prices, particularly those for low-sulfur residual oil, can influence gas prices. In turn, changes in gas prices relative to oil prices may affect purchasing decisions by pipeline company customers, pipeline throughput levels, and producer exploration and development decisions.

Weather. Weather still has a substantial impact on revenues because changes in the demand for gas affect wellhead prices and pipeline company and LDC throughput.

Interest Rates and Tax Policy. Because the industry is highly leveraged (i.e., it has a high proportion of debt relative to assets), low interest rates have been instrumental in helping gas industry participants reduce their financing expenses.

All segments of the industry are operating in environments with increased competitive pressures, both within the natural gas industry and from other fuels. For example, competition from low-priced oil keeps downward pressure on earnings; unbundling provisions of Order 636 are enhancing competition among the pipeline companies; pipeline companies and LDC's are competing in the secondary capacity market; and LDC's face competitive pressures from large industrial customers threatening to bypass their systems if costs are too high.

The increased presence of market forces has dramatically altered the risks and rewards facing the different segments of the gas industry. For example, the price of gas supplies now exhibits more volatility within a year than it formerly exhibited over several years (Figure 29). Moreover, various provisions of Order 636 are beginning to redistribute risks within the industry. For example, LDC's now bear greater supply risk, as a result of the unbundling requirements, while pipeline company revenues are now less sensitive to throughput levels because of straight fixed-variable (SFV) rate design.

Performance Tied to Regulatory and Legislative Changes

The impact of regulatory changes on the financial performance of the industry can be evaluated along a regulatory-market continuum (Figure 30). At one end of the

[69] Koch Gateway Pipeline Company, formerly United Gas Pipe Line Company, which also filed for Chapter 11 bankruptcy, was not included in the sample because it is not a publicly traded company.

Indicators of Financial Performance

Several measures of financial performance are used to evaluate a firm's debt management, profitability, and market valuation. Using these measures, each segment of the gas industry can be examined separately over time to see if the financial trends have either improved or deteriorated. In addition, the segments can be compared with one another, as well as with an industry average, in order to determine their comparative financial conditions.

Debt Management

Standard & Poor's Bond Rating

High Quality: AAA to AA
Investment Grade: A to BBB
Substandard: BB to B
Speculative: CCC to D

Standard & Poor's Corporation (S&P), a major credit rating agency, ranks bonds from AAA down to D, depending on its assessment of how the investment community views the creditworthiness of different companies. Triple or double A bonds are extremely safe, single A and triple B bonds are strong enough to be "investment grade," double and single B bonds are substandard, and triple C to D are considered speculative. Since many institutional investors are prohibited from purchasing bonds below investment grade, bonds ranked below triple B are commonly referred to as "junk bonds." Bond ratings, which reflect the company's probability of going into default, represent how potential creditors may view the riskiness of lending money to a company.

Long-Term Debt as a Percentage of Total Invested Capital
(Debt Capitalization)

This ratio represents the extent to which a firm's operations are funded with long-term debt (leverage), affecting investors' perceptions of the firm's financial strength. For instance, a highly leveraged firm faces more risk of financial distress in times of economic downturn because interest on the debt, in contrast to stock dividends, must be paid regardless of operating income levels. On the other hand, a firm with a low debt ratio may be able to endure periods of lower operational activity because its interest payment obligations will be lower.

Times Interest Earned (TIE) Ratio
(Interest Coverage Ratio)

Defined as earnings before interest and taxes divided by total interest charges, the TIE ratio measures the extent to which operating income can decline before a firm is unable to meet its annual interest costs. The TIE ratio is one of the primary means by which lenders and rating agencies measure the risk of financial distress. Since the TIE ratio is used to gauge a firm's ability to repay debt, the lower this ratio, the higher the probability that a firm will encounter financial distress. Conversely, a firm with a high coverage ratio should be able to meet its debt obligations, all other things remaining equal.

Profitability

Achieved Return on Common Equity (ROE)

The achieved rate of return on common stockholders' investment, a key measure of profitability, is the ratio of net income after taxes to common equity. For regulated industries with cost-based pricing, it is useful to examine this ratio to determine if firms have achieved the level of financial performance allowed by regulators. For example, if the achieved rate of return is lower than allowed, a firm might request higher allowed rates of return from regulators. Conversely, an extremely high achieved rate of return may imply regulatory laxity (usually temporary).

Market Valuation

Price/Earnings (P/E) Ratio

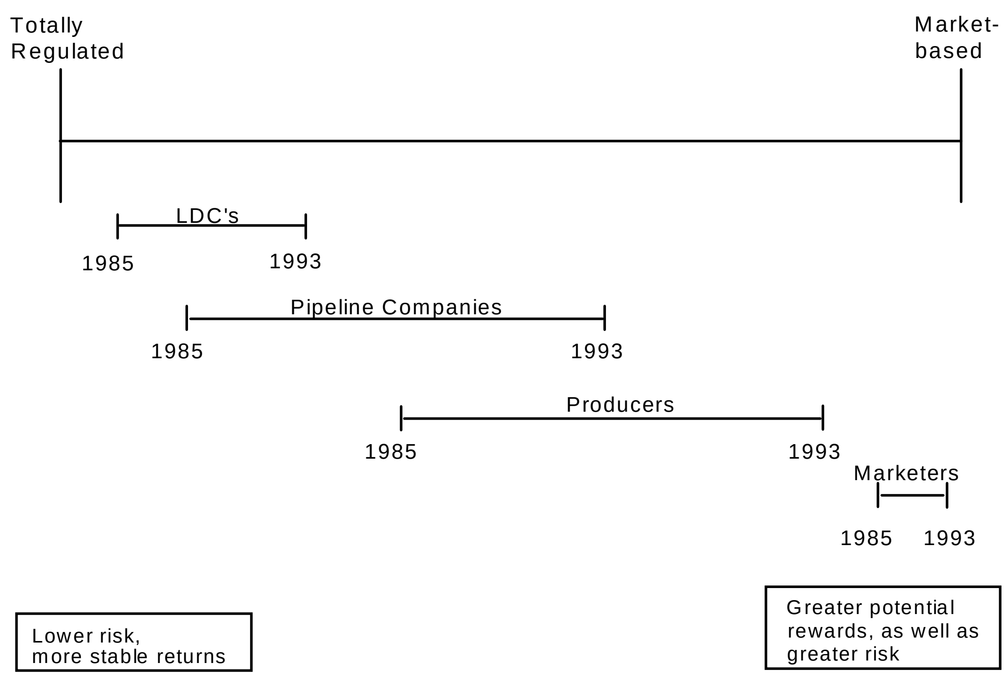
This ratio is defined as average stock valuation divided by net income after taxes. It is a measure of market value reflecting how much investors are willing to pay per dollar of reported profits. Other factors remaining constant, low P/E ratios may signal poor growth prospects for a company. Note that since earnings per share are generally somewhat volatile, an extremely high or low P/E ratio in a given period may show that investors expect a change in earnings.

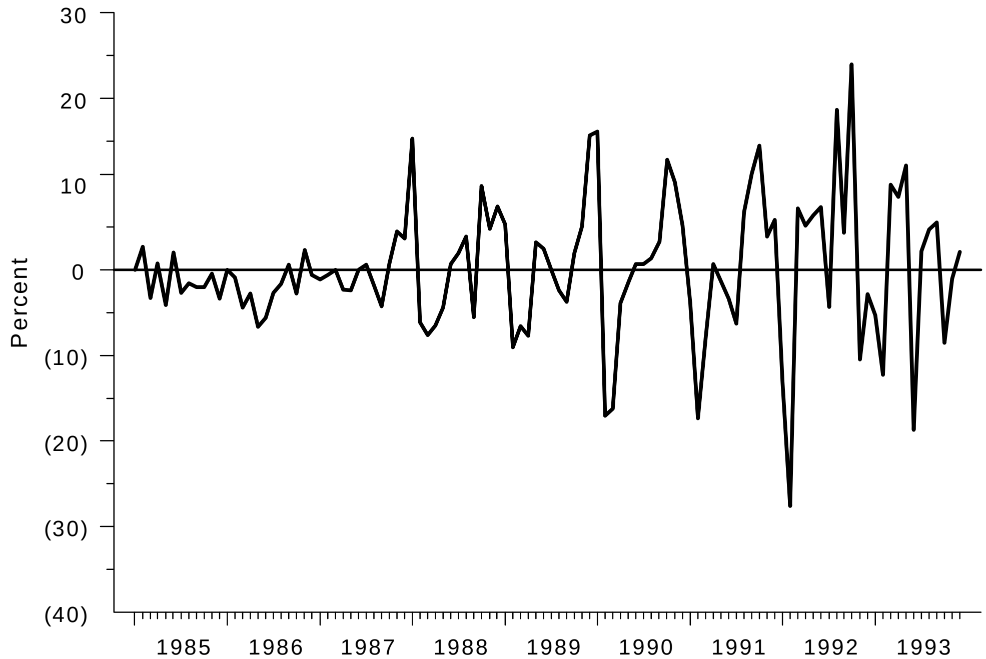
Market/Book (M/B) Value Ratio

The ratio of a company's average market valuation to its book value (common equity) gives another indication of how investors regard a company. Firms with high levels of profitability often sell at higher multiples of their book value than those with low levels. In regulated industries, extremely high market/book ratios may again imply regulatory laxity, if investors have purchased the firms' stock with the belief that higher-than-allowed levels of return could be achieved.

Figure 29. Percent Changes in Monthly Wellhead Prices, 1985-1993

Figure 30. The Regulatory-Market Continuum Within the Natural Gas Industry





Source: Energy Information Administration (EIA), Office of Oil and Gas: derived from EIA, Integrated Modeling Data System data base corresponding to the *Monthly Energy Review*, April 1994.

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

spectrum, market forces determine financial performance. The financial rewards for companies along this part of the spectrum are potentially large, but so too are the risks. At the opposite end of the spectrum, regulation plays the primary role in determining a company's financial performance. The financial rewards are usually lower for totally regulated companies, because they face fewer market risks stemming from their franchise monopoly rights and high barriers to entry. For the gas industry, placement along the continuum has not been static. All segments of the industry are now more exposed to market forces than they were a decade ago. As a result, the business environment for all segments has become more volatile. The two segments that have moved the most along this spectrum, the producers and the pipeline companies, have also been exposed to the most difficult changes. The transition to a more competitive wellhead market resulted in the absorption of billions of dollars of take-or-pay costs by both producers and pipeline companies. The recent restructuring of pipeline company services under Order 636 is resulting in several billion dollars of transition costs.[70]

In 1993, LDC's represented the most heavily regulated segment of the industry. Marketers, at the other extreme, represented the segment whose financial performance was most closely linked with market-determined factors. The risks and rewards facing each segment are partly determined by where that segment lies along the regulatory-market continuum. For example, the return on common equity (ROE) for LDC's has been relatively stable over time, reflecting lower risks and lower potential rewards. In contrast, ROE for the producers, both majors and independents, has been extremely volatile, reflecting the shift toward more competition at the wellhead. Although it is difficult to quantify similar financial impacts for marketers, consolidation among these companies since 1985 certainly is an indicator of the market-based risks they have faced. As might be expected, the financial performance of interstate pipeline companies, which have offered a mixture of regulated and market-based services since the start of open access, has demonstrated both stability and volatility, depending on the time period.

Improvement Shown from 1992 to 1993

The financial performances of the major producer, pipeline company, and local distribution segments of the industry generally improved from 1992 to 1993, while low oil and gas prices in the fourth quarter of 1993 contributed to weaker financial performance for the independent producers (Table 12).[71] However, in some areas, like debt management, all segments of the industry improved. Debt capitalization rates declined between 3 and 8 percent during 1993, in contrast to a slight increase (less than 1 percent) for the S&P 500. Although interest coverage for the S&P 500 was up 20 percent, the gas industry, excluding the independent producers, showed even greater improvement, with increases ranging between 22 and 34 percent. Interest coverage for the independents declined by almost 16 percent.

Industry profitability, measured by achieved rates of return on common equity, also improved substantially. Rates of return for interstate pipeline companies and LDC's improved by 76 percent and 171 percent, respectively, compared with an increase of 92 percent for the S&P 500. The return on equity of the independent producer segment declined in 1993, largely as a result of low gasprices in the fourth quarter. This decline is in contrast to increases in the S&P 500 and other industry segments, which had returns on equity ranging from 9 to almost 14 percent in 1993.

Investors have taken favorable notice of the generally improved performance of the natural gas industry. The price/earnings (P/E) ratios for all segments, including the independent producers, rose. Increases ranged from 1 to 38 percent, while the S&P 500 declined by nearly 12 percent. Market/book (M/B) value ratios for all industry segments showed greater increases, ranging from 12 to 22 percent, while the S&P 500 rose 12 percent.

Indicating improved investor confidence in the natural gas industry, the stock prices for all segments increased more than the S&P 500 in 1993. The S&P 500 reported an average stock price gain of 6 percent, while the major producers reported a 19-percent gain, the pipeline companies a 12-percent gain, the independent producers a 22-percent gain, and the LDC's a 14-percent gain (Figure 31).

Financial Trends Since Open Access

As discussed earlier, the less regulated the industry, the more its financial performance is driven by the market. Each segment of the natural gas industry differs depending upon the degree of regulation, and the financial statistics of each segment vary accordingly. The analysis evaluates three broad measures of financial performance during the period from 1985 through 1993:

- Debt management

[70]Some analysts contend that many of these costs would have occurred anyway and therefore do not reflect an added cost of restructuring gas services.

[71]Adequate data for the marketer/aggregator segment of the industry are not available for comparison.

Table 12. Industry Segment Financial Highlights, 1992 and 1993

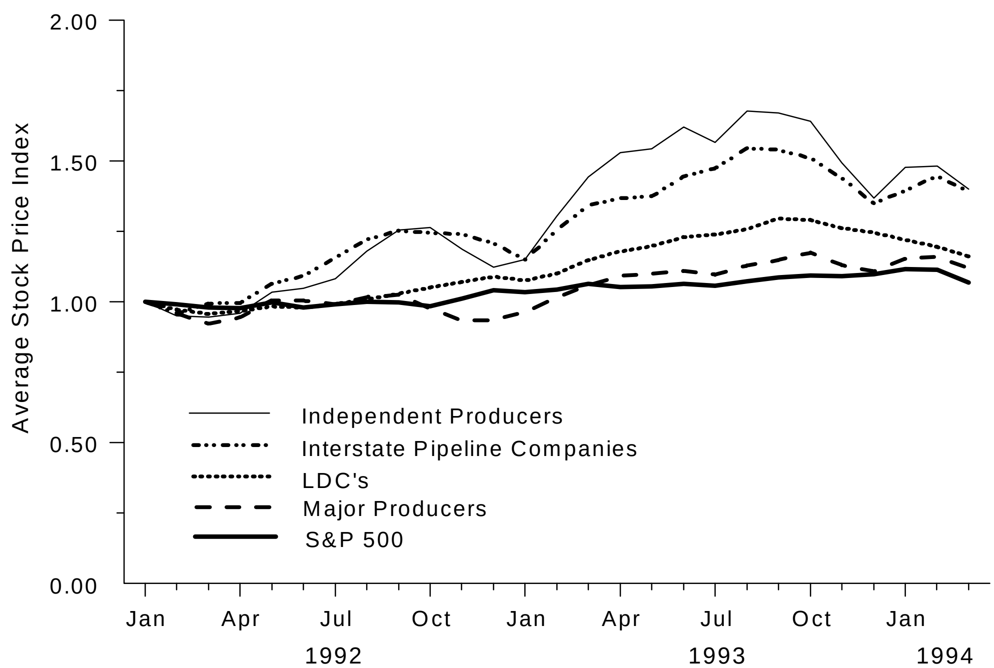
Financial Performance Measures	Producer Segment: Majors 1992	Producer Segment: Majors 1993	Producer Segment: Independents 1992	Producer Segment: Independents 1993	Pipeline Segment 1992	Pipeline Segment 1993	LDC Segment 1992	LDC Segment 1993	S&P 500 1992	S&P 500 1993
S&P Bond Rating	AA	AA	BB+	BB+	BB+	BB+	A	A	N/A	N/A
LT Debt as a % of Invested Capital	30.10	28.85	53.93	52.21	54.61	50.39	48.83	46.46	45.91	46.18
Times Interest Earned Ratio	3.93	4.8	1.46	1.23	1.74	2.33	2.42	3.07	2.12	2.55
Rate of Return on Common Equity (%)	9.05	13.74	1.99	1.21	6.23	10.97	4.09	11.07	4.77	9.18
Price/Earnings Ratio	15.14	16.4	21.50	29.61	13.18	16.57	14.38	14.48	17.91	15.78
Market/Book Value Ratio	2.07	2.38	1.85	2.18	1.53	1.86	1.56	1.75	2.36	2.65

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

Note: Pipeline segment includes Columbia Gas System. LDC segment represents gas-only distribution companies. Ratios for the S&P 500 were calculated based on data available through the S&P "Compustat" database aggregate file. For calculation of ratios, annual data were used from 1985 to 1993. Bond rating information was limited for the independent producers and LDC's. For more information on data sources and calculations on measures of financial performance, refer to Appendix C.

Source: Energy Information Administration, Office of Oil and Gas: derived from Standard and Poor's Compustat Services, Inc., "Compustat" database, April 1994.

Figure 31. Stock Price Index



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

Note: Stock prices are indexed to 1 by dividing each stock price series by its value in January 1992.

Source: Energy Information Administration, Office of Oil and Gas: derived from Standard and Poor's Compustat Services, Inc., "Compustat" database, April 1994.

- Profitability
- Market perception.

Improvement in Managing Debt

Bond ratings provide a sense of how the credit community perceives a firm's debt management effectiveness (Figure 32). For example, companies with a high percentage of debt relative to total invested capital are typically viewed as being risky. Additionally, firms with low interest-coverage ratios also are perceived adversely by potential creditors. Poor credit ratings result in high capital costs because creditors expect a higher risk premium.

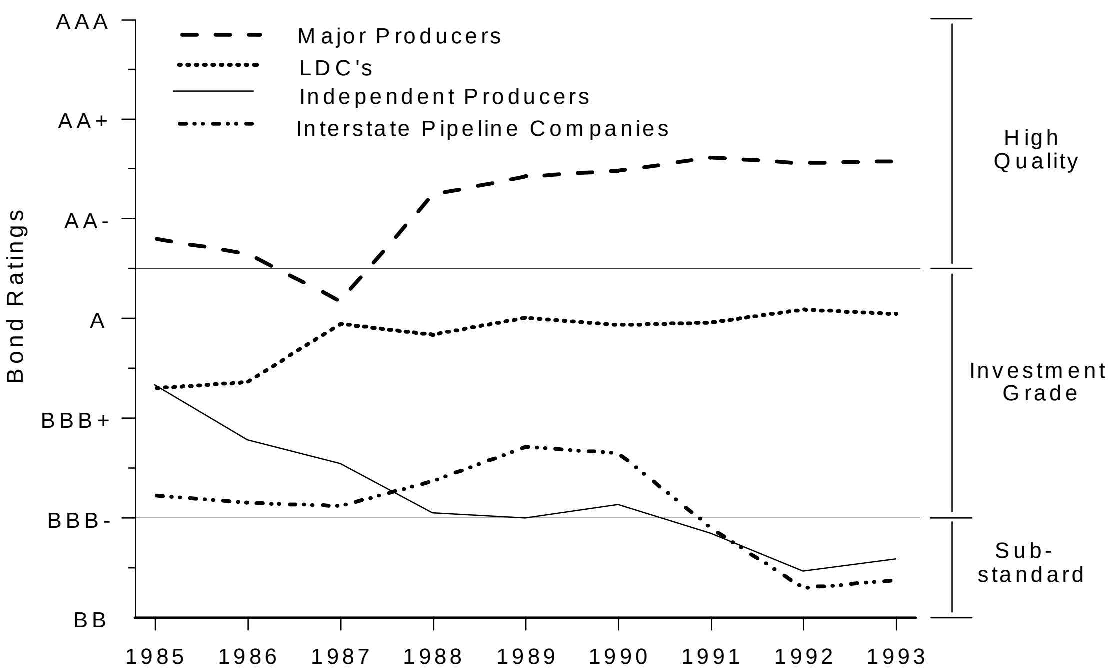
The major producers, throughout the open-access era, have been viewed the most favorably by creditors. Their average bond ratings have generally been high quality, except in 1987 when the average rating slipped to investment grade. This is primarily because major producers, in addition to having substantial assets that can be used as collateral, are also internationally diversified. In contrast, the independent producers' financial success is more directly linked to gas prices. For this reason, bond ratings for the independents have declined to substandard levels as a result of the price collapse of 1986. Like the independents, pipeline companies operating during the oil and gas price collapses were hit with severe financial problems. Their average bond ratings were hovering above substandard until 1991. The bankruptcy filing of Columbia Gas Systems brought the average bond rating to substandard levels.

In 1993 a slight increase in bond ratings occurred, as creditors perceived a shift of risk away from the pipeline company segment toward the LDC segment. Historically, in stark contrast to the pipeline industry, LDC's have been insulated from any major risks. Operating under regulated rates in noncompetitive environments has enabled the LDC's to maintain solid investment grade ratings.

Most Segments Experience Higher Profits

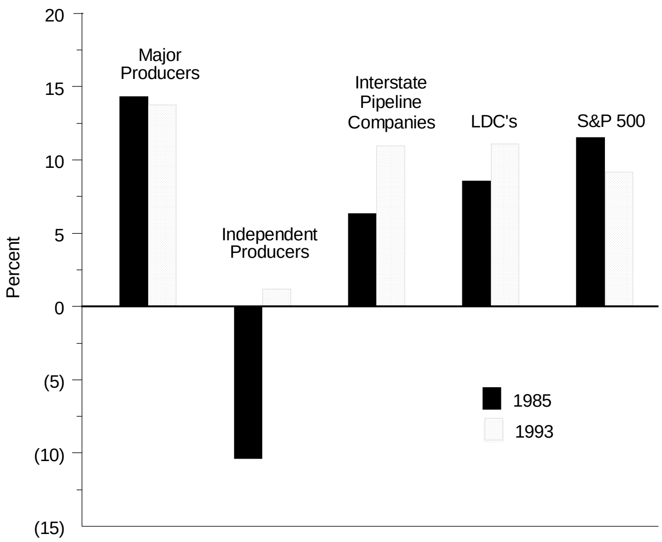
The major producers, with diversified operations, were able to earn substantial returns, even in times of economic decline, and have consistently outperformed the S&P 500. Yet, the returns of major producers were slightly lower in 1993 than in 1985, while the profitability of the other segments was higher (Figure 33). Independent producers are very vulnerable to changes in gas prices, as represented by the losses incurred when prices

Figure 32. Average S&P Bond Ratings



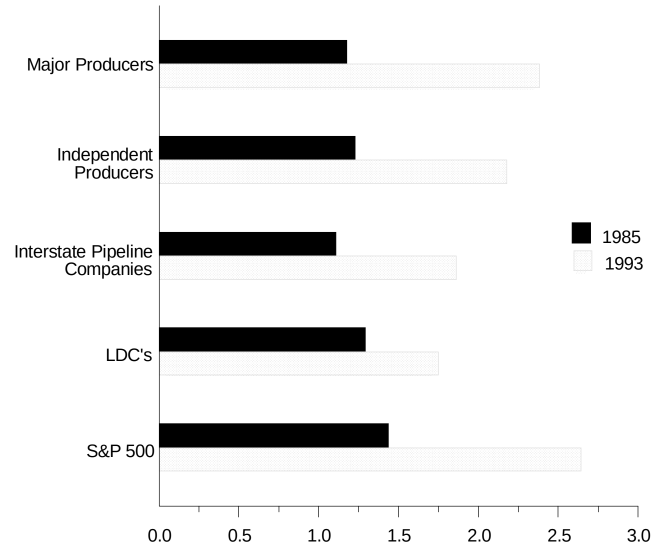
LDC=Local distribution company. S&P=Standard and Poor's.
Note: Bond rating information was limited for the LDC's and independent producers (see Appendix C).
Source: Energy Information Administration, Office of Oil and Gas: derived from Standard and Poor's Compustat Services, Inc., "Compustat" database, April 1994.

Figure 33. Rates of Return



LDC = Local distribution company. S&P = Standard and Poor's.
Source: Energy Information Administration, Office of Oil and Gas: derived from Standard and Poor's Compustat Services, Inc., "Compustat" database, April 1994.

Figure 34. Average Market/Book (M/B) Value



LDC = Local distribution company. S&P = Standard and Poor's.
Source: Energy Information Administration, Office of Oil and Gas: derived from Standard and Poor's Compustat Services, Inc., "Compustat" database, April 1994.

began to decline in 1985. Although the rate of return for this segment was higher in 1993 than in 1985, a certain degree of vulnerability to weakening energy prices is still apparent. The profitability of the pipeline companies was less stable than that of the LDC's, mainly because LDC's have been insulated from competition, whereas pipeline companies have operated in competitive environments but within the constraints of regulation. Both segments showed greater profitability in 1993 than in 1985.

Market Perceptions of the Segments

The market/ book (M/B) value ratio provides some indication of how investors perceive the industry segments over time. In 1985, LDC's had the highest M/B value ratio, in part, because they were largely insulated from the consequences of falling oil and gas prices (Figure 34). The majority of costs resulting from take-or-pay settlements were ultimately either passed on to the captive consumers or absorbed by producers and pipeline companies.

The M/B value ratios for all segments of the industry are substantially higher than in 1985. It appears that investors have been somewhat bullish on the producer segment recently, both majors and independents. It is interesting to note that the interstate pipeline company segment now has a slightly higher M/B value ratio than the LDC segment, perhaps reflecting investors' perceptions of the shift in risk away from pipeline companies toward LDC's. Also, note that no segment has a higher M/B value than the S&P 500.

Financial Performance of the Industry Segments

Producers

The financial performance of the producers was measured for a sample of large, internationally diversified, oil and gas companies (majors) and independent producers (see box, p. 105). In the United States, the independent producers account for approximately 61 percent of domestic gas production and hold over 66 percent of domestic gas reserves.

Extensive restructuring of operations has left many gas producers in better financial shape than they have been for a number of years. Balance sheets have improved as producers paid down debt, lowered costs, and found reserves more efficiently. Lower debt results in lower interest payments, which, together with reduced costs, contributes to higher net revenues. From 1985 to 1992, long-term debt declined from 32 to 29 percent of invested capital for major producers. Between 1982 and 1992, finding costs were slashed 75 percent and reserves added per exploratory gas well completion increased more than threefold.

Natural gas, which until the mid-1980's had been a secondary fuel for many producers, is now of primary importance. Gas consumption is expected to rise as new markets and uses for

Financial Performance Indicators for the Producer Segment

The producer segment of the natural gas industry comprises both large, internationally diversified oil and gas companies and domestic independent producers. The measures of financial performance below show how both groups have fared in the past decade. Gas prices have a greater effect on independent producers, as a group, than on the majors, because major producers can frequently recoup losses on the production end of their business from profits made in refining, petrochemicals, and marketing. Also, the majors earn income from overseas assets, which further cushions the impact of volatility in domestic gas prices. As a result, the majors generally outperformed the S&P 500, while the independents significantly underperformed this stock index.

In the wake of the 1986 oil price collapse, a wave of restructuring and downsizing boosted the profitability of the majors. At the same time, higher earnings from petrochemicals, refining, and marketing helped offset lower earnings from oil and gas production. As a result, the majors managed to keep their long-term debt as a percentage of invested capital at around 30 percent, as indicated by their relatively high interest-coverage ratio. The ability to pay off outstanding debt, coupled with their relatively high rate of return, earned them an AA rating in the bond market. In contrast, the independents, which are almost wholly dependent on oil and gas production for revenues, suffered through several years of low or negative rates of return. Those independents that did not go bankrupt in this time period incurred increasing debt, climbing to over 73 percent of invested capital in 1988. Consequently, the independents have had more difficulty paying their debt obligations, indicated by a low times interest earned ratio, and have been unable to shake a substandard bond rating.

Both the independents and majors are now being more favorably viewed by investors as the market/book value ratios of both groups continue to rise. Further, the 38-percent jump in price/earnings ratio for the independents from 1992 to 1993 could be a signal that investors expect better times for this group, even though earnings were down. Return on equity rose 52 percent between 1992 and 1993 for the majors and fell 39 percent for the independents.

Producer Segment	Financial Performance Measures	1985	1986	1987	1988	1989	1990	1991	1992	1993
Majors	Average Adjusted Stock Price	28.24	34.82	37.01	41.64	51.79	49.20	50.01	48.50	57.50
	S&P Bond Rating	AA-	A+	A	AA-	AA	AA	AA	AA	AA
	LT Debt as a % of Invested Capital	32.06	31.51	28.33	30.54	30.35	27.76	29.19	30.10	28.85
	Times Interest Earned Ratio	5.09	3.41	3.76	4.42	4.32	5.07	4.04	3.93	4.80
	Rate of Return on Common Equity (%)	14.30	10.34	10.64	17.67	18.56	17.78	12.54	9.05	13.74
	Price/Earnings Ratio	7.35	10.47	11.69	9.11	10.65	9.98	15.15	15.14	16.40
	Market/Book Value Ratio	1.18	1.31	1.69	1.65	1.99	1.92	2.01	2.07	2.38
Independents	Average Adjusted Stock Price	14.66	14.52	12.33	12.84	17.34	15.14	12.01	11.93	14.53
	S&P Bond Rating	A-	BBB+	BBB	BBB-	BBB-	BBB-	BBB-	BB+	BB+
	LT Debt as a % of Invested Capital	47.39	59.03	61.13	73.47	68.00	63.00	55.87	53.93	52.21
	Times Interest Earned Ratio	0.36	-0.56	0.52	0.91	1.59	1.46	1.21	1.46	1.23
	Rate of Return on Common Equity (%)	-10.39	-15.08	-7.85	-1.69	6.51	1.93	-1.17	1.99	1.21
	Price/Earnings Ratio	6.78	22.07	15.70	17.96	16.45	23.75	31.28	21.50	29.61
	Market/Book Value Ratio	1.23	1.45	1.96	1.84	2.32	2.63	2.05	1.85	2.18

LT = Long term. S&P = Standard & Poor's.

Note: Annual stock prices reflect the average adjusted price for December. Bond rating information was limited for the independent producers. See Appendix C for more information.

Source: Energy Information Administration, Office of Oil and Gas: derived from Standard and Poor's Compustat Services, Inc., "Compustat" database, April 1994.

gas are developed. In keeping with its growing importance, natural gas now accounts for the largest share of many producers' gross production revenues. The Independent Petroleum Association of America reports that 70 percent of its members' income comes from natural gas production.[72]

Between 1978 and 1985, revenues from gas production averaged about 38 percent of total revenues earned from oil and gas production combined. Gas revenues peaked at $68 billion (in 1993 dollars) in 1982, and then fell 26 percent between 1985 and 1986, while oil revenues plummeted 49 percent during the same period. Gas production revenues exceeded oil production revenues for the first time ever in 1993 (Figure 35), accounting for 56 percent or $38 billion of total oil and gas industry production revenues.

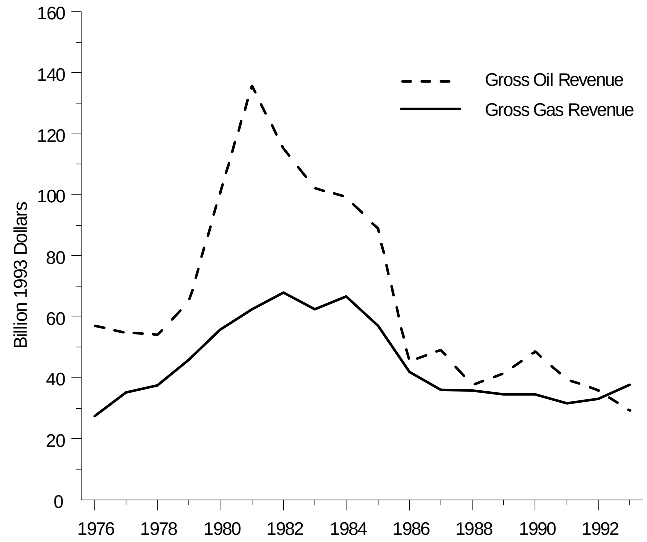
Some of the increased gas revenue share is because of the larger relative fall in oil prices since 1986. However, rising gas production accompanied by decreasing oil production accounts for much of the increase. Gas production climbed more than 14 percent between 1986 and 1993, from 17.5 quadrillion Btu to 20 quadrillion Btu. During the same period, oil production in the lower 48 States fell 23 percent, from 14.4 quadrillion Btu to 11.1 quadrillion Btu (Figure 36).

Higher gas prices, increased efficiency, lower costs, and rising production all contributed to improvements in producer revenues from natural gas production in 1993 (Table 13). In addition, the financial performance of gas producers has been affected by influences as diverse as "unconventional gas" tax credits and changes in pipeline transportation rates. However, changes in wellhead price usually have the most pronounced and immediate impact on producers' revenues.

Higher Gas Prices Spur Drilling

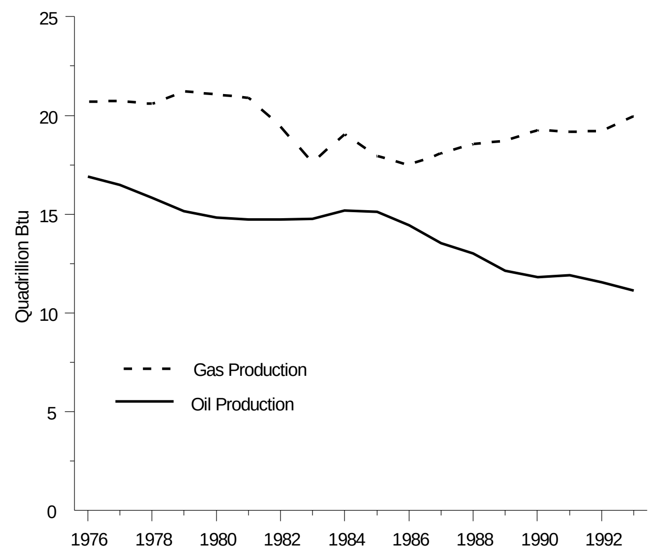
The dramatic rise in wellhead prices that started in the second quarter of 1992 and continued into 1993 provided a significant financial benefit to gas producers. Wellhead gas prices more than doubled between February and September 1992. The resulting increase in production revenues and profits allowed producers to finance a flurry of drilling activity toward the end of 1992 that continued into 1993. Also contributing to higher drilling was the belief among many producers that prices would remain strong as U.S. productive capacity began to tighten. In 1993, the average estimated wellhead price of $1.99 represented a 14-percent increase over the average wellhead price of 1992.

Figure 35. Estimated Gross Revenues from Lower 48 States Oil and Gas Production



Note: Nominal dollar values were converted to 1993 dollars using implicit gross domestic product deflators.
Source: Energy Information Administration, Office of Oil and Gas.

Figure 36. Lower 48 States Oil and Gas Production



Note: Gas production is marketed (wet) production converted to Btu.
Source: Energy Information Administration, Office of Oil and Gas.

[72]Bob Tippee, "IPAA Chairman Sees E&P as Creative Side of Business," *Oil and Gas Journal* (November 1, 1993), p. 41.

Table 13. Factors Influencing the Financial Performance of Producers

Factor	Description
Higher Gas Prices	Higher wellhead prices for much of 1993 was the leading factor contributing to increased revenues, profits, and drilling by gas producers. Gas prices rose 14 percent during 1993. This represents the largest increase in wellhead prices since 1982. However, the steep decline in oil prices in the fall of 1993 made fuel substitutes for gas such as low-sulfur residual oil more attractive to end users with dual-firing capabilities. This price competition, in turn, forced gas producers to lower prices in the latter part of 1993, which slowed revenue growth in what otherwise was a good financial year.
Repeal of Section 29 "Unconventional Gas" Tax Credits	Drilling of new unconventional gas wells slowed substantially in 1993. Current producers of unconventional gas from wells drilled before the tax credits expired will see tax benefits into the next century.
FERC Order 636	Unbundling and adoption of straight fixed-variable (SFV) rate design should lead to higher netback prices. Mandatory unbundling formally separated the sale of gas from the transportation of gas. Also, widespread introduction of SFV rate design permitted all producers to compete on a level playing field.
Long-term Contracts	Long-term contracts between producers and end users, once in decline, became more prevalent last year. This may stabilize producers' revenues and increase the assurance they need in planning exploration and development activity and securing future supplies. Volatility in revenue streams, however, has not been completely eliminated because many long-term contracts now are indexed to changes in an average fuel price (e.g., the spot price at the Henry Hub) or a basket of fuel prices. Hence, while producers may be more certain about the future firm demand for their gas, they still do not know what future revenue streams this demand will generate. Adding to this uncertainty, the displacement of spot gas purchases by longer term contracts could mean that long-term contracts will be increasingly indexed to spot gas that is traded in a thinner, less liquid, and perhaps more volatile market.
Alternative Minimum Tax (AMT)	Repeal of the AMT for certain classes of smaller independent producers has had a positive impact on their balance sheets. The Energy Policy Act of 1992 liberalized AMT calculations for independent producers, making it easier for them to attract capital.
State Tax Credits	Texas passed a number of tax incentives in 1993 to provide help to the ailing oil and gas industry. The New Oil and Gas Field Discovery Act grants a severance tax credit to producers in new areas. The Inactive Well Incentive Act provides a 10-year severance tax exemption on oil and gas produced from wells returned to service after 3 years or more of inactivity.
Environmental Regulations	Environmental regulations in recent years have had a mixed financial impact on producers. On the one hand, drilling moratoria in Federal wetlands, the Eastern Gulf of Mexico, and the Atlantic Seaboard continue to limit drilling options. Also, more stringent regulation covering wellsite waste has increased overall drilling and operating costs. Yet, a host of recent environmental initiatives favor the increased use of natural gas, which should improve the earnings outlook of the producers.

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

Finding rates and finding costs have improved significantly for domestic gas producers since the early 1980's and they contributed to improved profitability in 1993. Between 1982 and 1992, reserves added per exploratory gas well completed increased more than threefold, from 6.7 billion cubic feet (Bcf) to 21.3 Bcf. At the same time, finding costs (in 1991 dollars) fell from $0.51 to $0.13 per thousand cubic feet of gas discovered.[73] The lower costs translate into higher net revenues earned by producers.

Responding to higher wellhead prices, many producers increased production in 1993. Some of this production came from wells that had been shut down in early 1992, when producers could not cover operating costs. Responding to competition following pipeline company deregulation and increased demand from end users, producers increased production from 16.1 trillion cubic feet (Tcf) to 18.3 Tcf between 1986 and 1993.

To some extent, a cap exists on the degree to which prices can rise before dual-fired users switch to alternative fuels, such as low-sulphur residual oil. Toward the end of 1993, lower residual oil prices placed downward pressure on gas prices. In the third quarter of 1993, the price of low-sulfur residual oil delivered to electric utilities fell 7.3 percent from the price in the second quarter, averaging $2.61 per million Btu (MMBtu). During the same period, the price of natural gas delivered to electric utilities slid 4.5 percent, from $2.65 to $2.53 per MMBtu.

Repeal of the Section 29 "Unconventional Gas" Tax Credit

In 1993, producers earned additional revenues from tax credits for unconventional gas. This credit allows producers to deduct 95.3 cents per million Btu of coalbed methane production and 51.7 cents per million Btu of tight sands gas production from their income taxes. To qualify, producers had to begin drilling all wells before a January 1, 1993 deadline. The credit may be claimed on production from these wells until December 31, 2002.

Gas producers will see a positive impact on their cash flows from Section 29 tax credits during the next few years, after which the benefits will decline.[74] Because of the record number of unconventional gas wells drilled in the final few months of 1992 and the lag between drilling and the connection of a well to a pipeline, some of these wells were brought on line in 1993 and 1994. Also, unlike a conventional gas well, production from a coalbed methane well takes a number of years to reach its peak.

The effect of these credits on income has been and will continue to be substantial for some companies. For example, in its 1992 annual report, Enron Corporation states that it drilled approximately 500 tight sand gas wells in 1992 compared with 170 in 1991. The credit contributed $42.5 million to Enron's 1992 income, compared with $16.9 million in 1991. Enron earned $65 million in 1993 from the credit. Tight gas sands accounted for approximately 95 percent of Enron's 1992 reserve additions. Although producers can no longer claim a Federal tax credit on production from unconventional gas wells drilled after 1992, they can still capture benefits from various State drilling incentives. For example, Texas offers a State severance tax exemption for production from high-cost gas wells drilled through the latter part of 1996.

Supplying Gas Under Order 636

The implementation of Order 636 had several significant impacts on the natural gas supply industry. The unbundling of sales and transportation service in 1993 improved producers' access to storage and transportation rights. As a result, some producers began offering high-deliverability service or swing service to customers with unusual load requirements. Meeting the needs of these customers could be an important source of new revenues for producers in the future.

Furthermore, as pipeline companies eliminated their bundled sales services, many former pipeline company sales customers began direct contract negotiations with producers. In some cases, contracts with pipeline companies were renegotiated and assigned to these customers. Further, in contrast to the previous preference for spot gas purchases, many more shippers signed mid- and long-term contracts with producers. Even though the price of gas in many of these contracts was indexed and therefore subject to future price variations, the trend toward longer term contracts may help provide a more consistent stream of revenues that can be used to fund exploration and development activities.

Producers stand to gain substantial benefits from the straight fixed-variable (SFV) rate design being implemented by pipeline companies as a result of Order 636. SFV lowers the usage or volumetric charge for interruptible transportation service because the fixed costs associated with return on equity and related taxes shift into the reservation fee.

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[73]Energy Information Administration, *Natural Gas 1992: Issues and Trends*, DOE/EIA-0560(92) (Washington, DC, March 1993), p. 42.

[74]To qualify for Section 29 credits, producers had to drill either a "tight sands" gas well or a coalbed methane well before January 1, 1993.

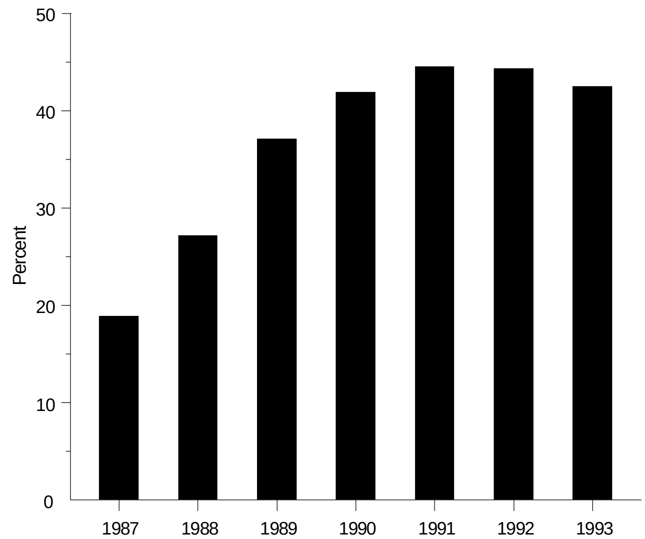
Customers who buy gas on a marginal cost basis will be attracted to the lower prices associated with interruptible transportation service. In addition, competition within the gas industry should increase because the price distortions inherent in modified fixed-variable (MFV) commodity charges will no longer exist.[75]

Marketers

The development of open-access transportation service in the mid-1980's created opportunities for companies to sell gas, often rebundled with interruptible transportation, at unregulated prices that were lower than the prices paid by pipeline company customers for regulated sales service. Gas marketing companies evolved to provide this new service. Since the start of open access, marketers have become an increasingly important link in the gas supply chain. The marketers' share of total deliveries (transportation and sales) increased from just a few percentage points in 1984 to 43 percent in 1992 (Figure 37). As recently as mid-year 1993, marketers' share in total carriage was 49 percent.[76] The trend toward increased rebundling has continued under FERC Order 636.

Marketers are now offering a wider array of services, including supply aggregation, supply procurement, balancing, capacity reservation, storage facilities, and risk management services. While many LDC's and end users may wish to purchase these services on their own, others are clearly using marketers to repackage these services, mimicking the former pipeline sales service. Creating different value-added combinations of supply and transportation service has led to increased revenues and profits for marketers under industry restructuring.

Figure 37. Marketer Share of Total Deliveries



Note: 1993 based on the first 6 months of the year.
Source: Interstate Natural Gas Pipeline Association of America, *Carriage Through the First Half of 1993,* December 1993.

The rebundling of supply and transportation capacity, which began with Order 436, has mushroomed into an environment where firms must offer many services to remain competitive. In this environment, many marketers have consolidated in order to remain competitive, while many smaller firms have gone out of business. Natural gas marketers continue to mature as a segment. The evolution and financial well-being of this segment of the industry will depend on several issues, such as its ability to capitalize on new business opportunities, market hubs, and storage access, and to maintain creditworthiness (Table 14).

It should be noted that reporting financial statistics for the marketers is difficult because they are usually privately held companies and may be subsidiaries of larger parent corporations. There are no formal government financial surveys to which these companies must respond. As a result, the evaluation of the financial performance of this segment is qualitative and based more on anecdotal information than for the other segments.

Consolidation Trends Continue in 1993

For the gas marketing industry, 1993 was another year of consolidation, with increased mergers and acquisitions, and more bankruptcy filings (Table 15). Marketers merged with other marketers as well as with producers. Meanwhile, credit difficulties, which have plagued the industry in the past, forced more companies to file for Chapter 11 protection in

[75]MFV rate design can distort prices paid by customers purchasing transportation or sales service on pipeline systems with assets of varying ages. The commodity charges levied by pipeline companies under MFV are a function of the age of the assets comprising the system. For example, a customer of a pipeline company with largely depreciated assets may pay considerably less for gas transportation than another customer shipping gas on a pipeline system with relatively new, undepreciated assets. Pipeline systems with fewer depreciated assets have higher rate bases. Because rate of return is earned against the rate base, all other things remaining equal, the larger the rate base, the larger the return will be assuming a constant cost of capital. Under MFV, the commodity charge includes variable costs, the return on equity, and related taxes; under SFV the commodity charge is strictly a function of variable costs. For a detailed discussion of price distortions relating to MFV rate design, see: Energy Information Administration, *Natural Gas 1992: Issues and Trends*, DOE/EIA-0560(92) (Washington, DC, March 1993), Chapter 4.

[76]Interstate Natural Gas Pipeline Association of America, *Carriage Through the First Half of 1993,* Report No. 93-4 (December 1993), Table A-1.

Table 14. Factors Influencing the Financial Performance of Natural Gas Marketers

Factor	Description
Rebundling	New business opportunities exist for marketers to rebundle services such as supply, gathering, balancing, storage, and transportation to meet the needs of their customers. Smaller local distribution companies (LDC's) and some industrial end users may be more inclined to use rebundled services offered by marketers because of a lack of broad expertise.
Industry Consolidation	In an effort to stave off fierce competition and stringent credit requirements, marketing industry consolidation continued in 1993. Order 636 will produce more opportunities for marketers overall, but growing competition may lead to the development of fewer, but larger firms.
Credit Availability	Credit requirements for marketers have become increasingly stringent. Marketers are required to provide proof of financial security before receiving a line of credit to purchase gas from producers. Because marketers serve as the intermediary between a buyer and seller of gas (or capacity), they need credit to serve as collateral in case one of the parties to the transaction withdraws.
Risk Management Services	Effective use of price risk management techniques is an important way for marketers to gain a comparative advantage over their competitors by providing lower cost gas and limiting the price exposure of their customers. Furthermore, providing price risk management services may become an increasingly important source of revenue for marketers. These tools fall into two main categories: New York Mercantile Exchange traded tools (i.e., natural gas futures contracts and natural gas options contracts) and off-exchange financial instruments (i.e., forward contracts, natural gas swaps, and natural gas options).[a]
Market Hubs	Market hubs pose two major financial advantages for marketers. First, marketers can develop and manage market hubs. Second, market hubs let marketers have greater access to markets and reach more customers.
Storage Services	Selling unbundled storage capacity rights gives marketers new opportunities to earn revenues. Also, buying storage capacity rights allows marketers to balance flows internally, enabling them to offer higher quality services.

[a]"Financial Instruments Help Producers Hedge Gas Deals in Volatile Market," *Oil and Gas Journal,* November 1, 1993.
Source: Energy Information Administration, Office of Oil and Gas.

1993. The past year showed that Order 636 will produce more opportunities for marketers overall, but growing competition may lead to the development of fewer, larger firms.

There are several reasons why so many mergers and acquisitions involving marketers took place in 1993. First, marketers purchased or teamed with other firms to diversify the mix of services they offer. As margins for reselling gas decline, marketers have to find new ways to expand the services they can offer. Rather than creating new, in-house divisions, some marketers have purchased or teamed with other firms that can strategically help extend their service options. Second, alliances with producers became more common as marketers sought more secure supplies of gas and producers sought greater marketing expertise. Third, merging with other firms allowed marketing companies to reach more customers. Wider geographical markets enable marketers to increase market share. Last, some marketers consolidated with other companies to strengthen their financial position. By merging with larger, more established firms, some smaller or mid-sized marketers were able to eliminate concerns about their credit risk.

Marketers Must Meet Tougher Credit Standards

Some marketers were forced out of business because they were unable to meet stringent credit requirements.[77] While

[77]David Givens, "Credit Crunch: Banks Take a Close Look at the Marketing Business in the Wake of Bankruptcies," *Natural Gas*, Summer 1993, pp. 48-49.

Table 15. Recent Examples of Marketing Industry Consolidation

Companies	Dates	Reasons
Enron Gas Services acquires Access Energy	September 20, 1992	Access Energy lacked additional resources for supply and risk management divisions and Enron wanted to expand its presence in the end-user market.
Tenneco acquires Entrade	January 5, 1993	Tenneco wanted to acquire a national marketer that possessed strong alliances with natural gas producers. Entrade wanted access to Tenneco's diversified risk and supply management services.
Santa Fe acquires 40 percent of Hadson	August 2, 1993	For Hadson, the relationship granted greater supply security to support long-term contracts and improved relationships with producers. For Santa Fe, the agreement has enhanced their marketing division and risk management services.
CMS Gas Marketing forms joint venture with Fellon-McCord Associates	September 13, 1993	Fellon-McCord Associates wanted to increase market share in the east-central United States.
GasMark bankruptcy	July 2, 1993	GasMark was unable to meet a $1 million margin call resulting from an expiring futures contract.
Sunrise Balancing Group and Pentzer Gas Trading form joint venture	October 18, 1993	Sunrise Balancing Group operates business functions such as arranging purchases and sales, managing transportation, nominations, balancing and dispatching, and accounting. Pentzer Gas takes title to the gas and holds the sales contracts.

Source: Pasha Publications, Inc., *Gas Daily*, various issues.

credit availability may affect any industry, it is the lifeblood of gas marketing firms. This stems from the unique role the marketers fulfill in the gas supply chain: they frequently act as the intermediary between a buyer and seller of gas or capacity and need credit to serve as collateral in case one of the parties to the transaction defaults. To get credit, many marketers now have to disclose more detailed financial information to producers or lenders than they did previously. Exceptions may be made for marketers with good payment records.

Marketers not considered creditworthy by a producer will not receive supplies. Credit is less of an issue for marketing firms owned by major producers or pipeline companies backed by asset-rich balance sheets. This provides their marketing subsidiaries with equity support to expand volume of throughput by using varied financing tools. By teaming with producers and pipeline companies, marketers were able to increase collateral backing of contracts with their suppliers and limit their exposure to credit risk in 1993.

Managing Financial Risk

Sophisticated risk management tools, such as futures, options, and swaps (see Chapter 3), allow marketers to manage their own, as well as their clients', financial or price risk. Marketers will in some cases provide risk management products separately without arranging the complete supply and transportation transaction for a client. Increasingly, marketing companies are staffing risk management divisions primarily to protect themselves against substantial losses in their own daily transactions with clients, as well as to allow for greater flexibility in pricing of their services.[78]

Risk management techniques have already had important financial consequences for marketers. First, the use of natural gas financial instruments has grown particularly fast,[79] in part because gas prices have been quite volatile the past several years. Marketers are the biggest players in this market. For

[78]Telephone conversation with Douglas Sato, IGI Resources, Inc. (January 28, 1994).

[79]At the close of 1993, the market for energy derivatives was estimated to be worth more than $60 billion. *Bloomberg Natural Gas Report*, Vol. 3, No. 2 (January 17, 1994).

example, in 1993 marketers comprised 60 percent of the positions in the futures market and 34 percent of positions in the options market.[80] Second, marketers can reduce the overall cost of acquiring and selling gas in today's market because of their knowledge of current activities in both the financial and physical markets and their expertise in engaging in both markets. Margins on reselling gas have become thin because of competition; the use and creation of financial tools effectively enables marketers to differentiate their services, gain more market share, boost their revenues, and increase profits. The financial downside is that using risk management techniques can result in substantial losses as well as gains. In 1993, a marketing company named GasMark could not cover a $1 million margin call for a futures contract and consequently went out of business.

Marketers Play Larger Role in Development of Market Hubs

The increased development of market hubs and pooling centers gives marketers greater access to transportation and supplies, enabling them to meet end-use demand in more diverse geographical locations. Market hubs connect pipelines, storage facilities, and reserves, and also offer such services as parking, wheeling, and balancing that previously would have been inaccessible (Chapter 2). By offering new hub services and reaching more customers, marketers will be able to increase their revenues and profits significantly.

In 1993, many marketers were active in the development of market hubs. Large marketers, like Natural Gas Clearinghouse (NGC), have been financing the construction of hubs. For example, Equitable Resources, Inc. recently acquired the Louisiana Intrastate Gas pipeline system (LIG). The company plans to extend LIG 12 miles to the Henry Hub (the largest market hub in the United States) and to integrate its growing Gulf Coast reserves and production into the LIG system. It will hook up nonaffiliated production to increase throughput and expand production, which will result in interconnections with several major markets.[81] Marketers who possess sophisticated information technology systems to track gas and to use hubs are well positioned to service end users and LDC's efficiently.[82]

[80]New York Mercantile Exchange.
[81]Steven Parla, *First Boston Equity Research* (September 27, 1993), p. 2.
[82]*Gas Market Listener* (September 7, 1993), p. 4.

Interstate Natural Gas Pipeline Companies

The restructuring of pipeline company services under Order 636, as was the case under Order 436, will likely have a substantial financial impact on the interstate pipeline industry. For pipeline companies, the open-access era has resulted in harsh financial reality (see box, p. 113). As of December 31, 1993, pipeline companies had absorbed nearly $3.6 billion of take-or-pay settlement costs. These take-or-pay costs, in part, resulted in the bankruptcy of two major systems (Columbia Gas System and United Gas Pipe Line). To endure this evolutionary period, many pipeline companies consolidated and incorporated several efficiency improvement measures (e.g., streamlined labor force and new information systems).

Several aspects of Order 636 directly influence the financial risks and rewards that pipeline companies will face (Table 16). Although the transition costs associated with this regulation have been estimated by the General Accounting Office at almost $4.8 billion, this should not impose significant financial risks on the pipeline companies because it is expected that FERC will allow the recovery of the majority of these costs.

In 1993, the interstate pipeline companies saw significant growth in income. Net sales for the pipeline companies (included in the sample) increased to $39 billion, a 13-percent increase from the level in 1992. This increase corresponds with a trend toward higher throughput. From 1991 to 1992, throughput rose by 8 percent, followed by an estimated 5-percent increase from mid-year 1992 to mid-year 1993.[83] As a result, net income in 1993 was almost $1.7 billion, a 95-percent improvement from that in 1992.

The Switch to SFV Rate Design

Under the modified fixed-variable (MFV) rate design, a pipeline company's return on equity and related taxes were recovered through a commodity (usage) charge, which was based on customer throughput levels. However, under the straight fixed-variable (SFV) rate design, these costs are

[83]Interstate Natural Gas Pipeline Association of America, *Carriage Through the First Half of 1993*, Report 93-4 (December 1993), Table A-2.

Financial Performance Indicators for the Interstate Pipeline Segment

The interstate pipeline industry has generally experienced financial difficulties since open access, mainly because of the oil and gas price collapses of 1986 and take-or-pay liabilities. For instance, from 1985 to 1986, achieved rates of return fell over 160 percent. Additionally, the amount of debt as a percent of invested capital increased, while the ability to cover interest payments, as measured by the times interest earned (TIE) ratio, became extremely low. The increased market/book value ratio reflects a reduction in total common equity at this time, caused by reduced retained earnings to cover losses on high-priced contracts. From 1987 to 1990, the pipeline industry gained experience operating under the open access environment, began reforming high-priced contracts, and started to develop more transportation-only services, although sales service was still a major source of revenue. In this period, pipeline companies saw improved financial performance, as the amount of debt remained relatively stable and achieved rates of return increased. This improved performance encouraged creditors and investors, as bond ratings were raised and market valuation increased. For instance, from 1988 to 1989, an 18-percent increase in market/book value occurred as rates of return increased to their highest level since open access was instituted.

However, in 1991 conditions for the interstate pipeline segment began to deteriorate somewhat as Columbia Gas System filed for Chapter 11 bankruptcy protection. With Columbia included in the sample, bond ratings dropped to substandard levels, along with a drop in interest coverage and achieved rates of return. Without Columbia in the sample, the changes were not as drastic; yet, conditions did worsen. In 1991, this resulted, in part, from a warmer-than-normal winter and an economic recession. Eventually, average bond ratings for the segment, even excluding Columbia, fell to substandard levels by 1992. In 1993, with the implementation of Order 636, financial indicators point to improved performance. Debt levels are down, and interest coverage is at its highest point since the start of open access. Achieved rates of return are also at their highest level in 8 years, as more companies have begun to use SFV rate design. Return on equity for pipeline companies increased more than 70 percent between 1992 and 1993. The market is responding, with a 22-percent increase in the market/book value ratio. The dramatic increase in the price/earnings ratio from 1992 to 1993 shows investors believe that pipeline company finances will further improve.

Pipeline Segment	Financial Performance Measures	1985	1986	1987	1988	1989	1990	1991	1992	1993
w/Columbia	Average Adjusted Stock Price	19.68	19.97	17.96	20.52	27.84	23.76	20.10	23.49	26.26
	S&P Bond Rating	BBB-	BBB-	BBB-	BBB	BBB	BBB	BBB-	BB+	BB+
	LT Debt as a % of Invested Capital	53.35	57.20	52.92	52.29	52.99	53.24	55.91	54.61	50.39
	Times Interest Earned Ratio	1.89	0.83	1.75	1.44	1.79	1.65	1.00	1.74	2.33
	Rate of Return on Common Equity (%)	6.32	-3.93	7.97	6.18	8.63	7.47	1.01	6.23	10.97
	Price/Earnings Ratio	10.94	13.00	12.04	13.42	14.66	16.00	17.36	13.18	16.57
	Market/Book Value Ratio	1.11	1.30	1.31	1.28	1.51	1.55	1.52	1.53	1.86
w/o Columbia	Average Adjusted Stock Price	18.57	18.35	16.61	19.61	26.58	22.34	20.25	23.70	26.41
	S&P Bond Rating	BBB	BBB-	BBB-	BBB	BBB	BBB	BBB	BBB-	BBB-
	LT Debt as a % Invested Capital	53.54	58.41	53.69	53.00	54.02	54.11	57.74	56.44	52.32
	Times Interest Earned Ratio	2.06	0.71	1.73	1.39	1.76	1.63	1.56	1.66	2.25
	Rate of Return on Common Equity (%)	8.05	-5.49	8.07	5.95	8.58	7.67	6.95	6.36	10.84
	Price/Earnings Ratio	10.94	11.99	11.26	13.38	14.81	15.38	17.36	12.95	17.47
	Market/Book Value Ratio	1.13	1.32	1.30	1.31	1.55	1.58	1.52	1.59	1.94

LT = Long-term. S&P = Standard & Poor's.

Source: Energy Information Administration, Office of Oil and Gas: derived from Standard and Poor's Compustat Services, Inc., "Compustat" database, April 1994.

Table 16. Factors Influencing the Financial Performance of Interstate Pipeline Companies

Factor	Description
The Switch to SFV Rate Design	The use of straight fixed-variable (SFV) rate design allows for the recovery of a pipeline company's return on equity and related taxes, regardless of throughput. This guaranteed recovery should reduce pipeline companies' financial risk in the short run. In the longer run, however, pipeline companies must ensure that their rates are competitively priced in order to maintain market share.
Capacity Release	The introduction of a secondary market for released capacity is expected to compete with pipeline companies' interruptible service. Pipeline companies may face increased risks in recovering costs if their interruptible service can no longer be actively marketed. However, pipeline companies may also be able to attract new customers into long-term contracts if they can demonstrate a viable secondary market for unneeded capacity.
Unbundling and the Elimination of Cross-Subsidies	Pipeline companies will no longer bear the risk of contracting for gas supplies. Additionally, pipeline companies that have become more efficient and can competitively price their services may gain market share in the post-636 environment where shippers can see the true costs of obtaining different services. However, those companies that had previously cross-subsidized inefficient parts of their sales service may lose market share if they are unable to adapt to this new environment.
Creation of Marketing Affiliates and New Services	To comply with Order 636's unbundling requirements, many pipeline companies created new marketing affiliates in 1993 to offer both unregulated gas supply and transportation service. Also, a number of new services are being offered by pipeline companies to increase revenues (see Chapter 2).
Recovery of Transition Costs	Transition costs differ from take-or-pay settlement costs because the Federal Energy Regulatory Commission (FERC) provides for the pipeline companies' recovery of <u>all</u> "prudently incurred" costs related to restructuring. While this may boost lender confidence in pipeline companies, uncertainty remains in FERC's determination of prudence.
Overcapacity	Excess capacity in some markets has forced pipeline companies to discount their transportation services substantially.
Creating New Market Hubs	Market hubs may promote increased gas use through more efficient use of the national pipeline grid. Development of market hubs may allow pipeline companies to provide transportation services to more end users.
Adoption of New Technologies	The increased use of real-time metering devices will become necessary on pipeline systems to maintain operational control, as transactions become more complex and pipeline companies no longer hold title to the gas on their systems. Additionally, as companies look to attract customers for long-term contracts, their future market share may depend on the accessibility and user-friendliness of their electronic bulletin boards (EBB's). Pipeline companies that provide timely and accurate customer-specific flow data may increase their market share.
Take-or-Pay Settlement Costs	Almost a decade after the oil and gas price collapses caught pipeline companies locked into high-priced contracts with take-or-pay clauses, some fallout still remains. Outstanding take-or-pay settlement costs continue to decline. However, most of what remains should be passed through to LDC's and, ultimately, to ratepayers. Columbia Gas Transmission remains under Chapter 11 protection from its creditors because it has not paid back its outstanding take-or-pay settlement costs. FERC has estimated that the pipeline industry has directly absorbed almost $3.6 billion of the $10 billion worth of take-or-pay costs incurred as of June 30, 1992.
Rolled-in Versus Incremental Rates	Pipeline companies may increase revenues by attracting new customers to their existing grid and by constructing new facilities. Pipeline companies may have difficulty in expanding their market areas because of the controversy surrounding the treatment of capital costs involved in pipeline expansion projects. "Rolled-in" pricing, in which the expansion costs are added to the companies' existing rate bases, is opposed by those customers who do not benefit from the expansion. However, "incremental pricing," which raises the rates to those customers who require new service along the expansion, may make rates prohibitively expensive.
Determination of "At-Risk" Conditions	Growth in the pipeline industry depends on the ability of companies to expand their market areas. However, current certification procedures make it difficult for companies to develop expansion projects unless capacity on the project is almost fully subscribed for a specific length of time. If this is not the case, the project is labeled "at-risk," and the company is not assured recovery of the project's capital costs. FERC intends to review the rules for new pipeline construction in 1994 to provide more flexible methods for determination of the need for new construction.

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

recovered through a reservation fee, which is paid by customers on a monthly basis, regardless of throughput, in order to reserve pipeline capacity. During the past 3 years, several companies implemented SFV rate design. In 1993, most of the interstate pipeline companies still using MFV switched to SFV under Order 636.[84]

The use of SFV rate design helps to ensure the recovery of a pipeline company's fixed costs, including return on equity and related taxes. This may improve the financial performance of pipeline companies because actual rates of return, using the MFV rate design in the open access era, have been much lower than FERC-approved rates (Figure 38).[85]

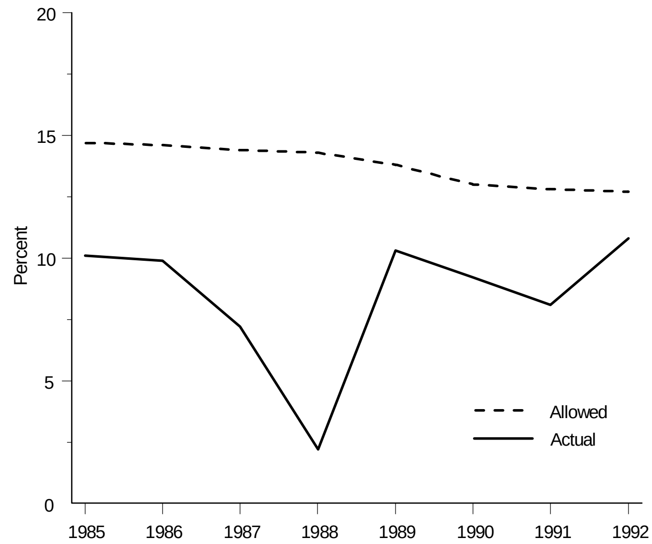
In the short run, a pipeline company may no longer be at risk for recovery of its return on equity because these costs are recovered regardless of throughput. However, in very competitive markets such as in California, pipeline companies may be forced to discount their firm transportation rates substantially in the future to maintain customers or increase market share.

Finally, although the switch to SFV rate design was mandated in Order 636, regulatory uncertainty still exists. As evidenced in the restructuring proceeding of Iroquois Gas Transmission, L.P., the newly appointed commission at FERC granted an exception to SFV for a customer because of pre-existing contract conditions (Chapter 2). While this may be the exception to the rule, it should be pointed out that the possibility does exist for future adjustments in rate design.[86]

The Development of a Capacity Release Market

The establishment of a secondary market for released capacity may have differing effects for various pipeline companies. For pipeline companies that offer a large amount of interruptible service, the capacity release market presents another form of competition that may affect their ability to sell interruptible transportation. In 1992, about 44 percent of

Figure 38. Allowed Versus Actual Pipeline Company Rates of Return



Note: The sample of companies used here differs from that used in the analysis in this chapter.

Source: Interstate Natural Gas Pipeline Association of America (INGAA). **1985-1990:** *Financial Health of the Pipeline Industry*, March 1992; **1991-1992:** Updated data provided by INGAA staff.

pipeline throughput occurred on an interruptible basis.[87] Thus, a key source of some pipeline companies' revenues could dissipate if they are not able to market their interruptible service successfully.

Some pipeline companies, however, may be able to capitalize on this new market because they could attract customers into signing long-term contracts. For example, shippers may be more willing to purchase long-term contract rights if they know they can resell these rights to a third-party for a small transaction fee. Also, the user-friendliness of a firm's electronic bulletin board may aid in attracting new customers. The ability of these pipeline companies to retain long-term customers, in turn, may make the pipeline companies more attractive to potential investors seeking assurance that there is long-term demand for the companies' services.

New Customer Services Develop

In the post-636 era, pipeline companies have the opportunity to increase revenues by creating new customer services that help to ensure a reliable source of energy. Companies that have storage facilities may benefit because end users, now responsible for purchasing their own gas, may hedge against supply disruptions by purchasing excess gas supplies and

[84]Notable exceptions include Iroquois Gas Transmission System, L.P., which was allowed to retain MFV for a customer with existing gas supply contracts tied to the MFV demand charge. See Chapter 2 for more information on rate design changes under Order 636.

[85]While pipeline companies are allowed to recover all of their fixed costs as well as the allowed return on equity and related taxes under SFV rate design, they lose the opportunity they had in the past to earn higher than the allowed return on equity if they sell more than the projected cost of service, market conditions permitting.

[86]In fact, SFV rate design is the fourth methodology used within the past 20 years. For a more detailed discussion on the evolution and changing purpose of rate design methodologies, see: Energy Information Administration, *Natural Gas 1992: Issues and Trends* (March 1993), Chapter 4.

[87]Interstate Natural Gas Pipeline Association of America, *Carriage Through the First Half of 1993* (December 1993).

injecting it into storage facilities. Other pipeline companies operating in more competitive environments may find that, in order to maintain or increase market share, they may have to enhance the quality and types of services they offer in order to differentiate themselves from competitors. Other companies may create risk management subsidiaries, which offer tailored services to customers wishing to minimize future price or supply risk (see Chapter 2).

A pipeline company could also create "capacity aggregator" affiliates to handle released capacity, purchasing small amounts of released capacity from several small customers and repackaging it for sale to customers requiring large capacities. This process could be analogous to the securitization of credit cards or mortgages, where investment banks create standardized securities from debts with varying maturities, rates, and associated risks. While this entity would technically be distinct from the transportation arm of the pipeline company, it would benefit from having a knowledgeable staff familiar with the pipeline company's operations.[88]

The Treatment of Transition Costs

Pipeline companies face large potential costs associated with the implementation of Order 636. Total costs have been estimated by FERC at over $4.8 billion. However, FERC has provided for the recovery of all costs that relate to pipeline company restructuring and which have been prudently incurred. The likely recovery of these costs has boosted lender confidence in the companies. As evidence of this, several pipeline companies have recently been removed from the Standard & Poor's Creditwatch "with negative implications" listing of companies that investors should watch closely.

On the other hand, pipeline companies still face regulatory uncertainty because they may be unable to recover liabilities that do not fit the transition cost guidelines set by FERC. Additionally, the recovery mechanisms outlined by FERC could make certain services unattractive to customers. For example, the provision that 10 percent of gas supply realignment (GSR) costs be recovered through a surcharge on interruptible service could make this service more costly than competing released capacity.

Local Distribution Companies

Of all the natural gas segments affected by restructuring, none will have to change its daily and long-term operations more than the LDC's. Still bound by the obligation to serve, LDC's must assume many of the responsibilities previously handled by pipeline companies. Some of these include supply aggregation; balancing daily and monthly gas requirements; and even purchasing their own storage, production, and gathering services. In many cases, these new responsibilities will force the LDC's to implement new risk management techniques. During the past few years the financial performance of the distribution segment of the industry has been very stable (see box, p. 117). However, in the post-636 era, the financial health of LDC's will be dependent on their ability to respond effectively to a number of different factors (Table 17). These factors are a direct result of the provisions of Order 636 and promise to increase the risks and uncertainty of conducting business.

Financial performance by LDC's, as reflected in increases in net income, was very strong in 1993. During 1993, net income for gas-only LDC's was over $1.2 billion, a 176-percent increase from the level in 1992. Increases in LDC throughput, attributable to colder-than-normal weather, and a greater volume of sales to residential and commercial customers, who buy higher priced gas, were the primary determinants of these financial trends.

Unbundling—More Risks, More Choices

In the past decade, LDC's have been gaining experience in purchasing wellhead gas and making transportation arrangements with pipeline companies. They now must deal with operational complexities that have traditionally been part of pipeline company service (Table 18). Because Order 636 requires pipeline companies to unbundle their services completely, LDC's have become responsible for contracting separately for adequate gas supplies, transportation capacity, and several other services needed to maintain system integrity (e.g., balancing, linepack, and storage). By transferring the merchant role (securing appropriate gas supplies) from pipeline companies to LDC's, substantial risk has also been transferred to the LDC segment of the industry.

The LDC merchant risk relates to supply and capacity procurement. For instance, LDC's face penalties relating to the balancing of receipts and deliveries. Additionally, to ensure sufficient gas supplies, LDC's must become knowledgeable about source reliability in order to develop an adequate portfolio of short-, mid-, and long-term supplies. Contract-related price risks can occur if, for example, a fixed-price supply contract is used and gas prices drop, or a contract

[88]For further information on this issue, see Theodore J.P. Biribin and Christopher J. Peterson, Science Applications International Corporation, "The Economics of Interruptible Transportation and Released Capacity in the Post-636 Era," Draft Working Paper #1 (November 1993).

Financial Performance Indicators for the Local Distribution Segment

Local distribution companies have traditionally been isolated from competition and risk under the oversight of State regulators. This has enabled them to maintain very high interest-coverage ratios and relatively normal levels of debt financing while also achieving very stable rates of return. As a result, they have secured solid investment grade bond ratings.

In 1988 their condition was downgraded slightly, as pipeline companies began passing through take-or-pay settlement costs. Debt financing increased in that year, interest coverage dropped, and returns decreased slightly. Investors took notice, as evidenced by a decreasing market/book value ratio. The financial condition rebounded in 1989, with returns reaching their highest point in the open-access era. In 1990 and 1991, financial results were down slightly, as debt continued to rise as a percent of financing, and interest coverage also fell. Achieved returns also fell, along with a slight decline in the market/book value ratio. In 1992, conditions were mixed: returns decreased but interest coverage increased. Yet, investors still viewed the segment favorably, causing the market/book value ratio to increase. This perception was valid, as 1993 saw increased rates of return, lower debt, higher interest coverage, and even further increases in market/book value. Return on equity for the LDC's increased 171 percent between 1992 and 1993.

As the effects of the implementation of Order 636 become more apparent, 1994 will be a critical period for local distribution companies.

Financial Performance Measures	1985	1986	1987	1988	1989	1990	1991	1992	1993
Average Adjusted Stock Price	17.69	19.94	18.84	18.66	23.29	21.21	20.53	22.78	26.06
S&P Bond Rating	BBB+	BBB+	A	A	A	A	A	A	A
LT Debt as a % Invested Capital	44.21	45.04	44.27	47.30	46.31	47.28	48.62	48.83	46.46
Times Interest Earned Ratio	2.81	2.67	3.01	2.51	2.49	2.04	1.95	2.42	3.07
Rate of Return on Common Equity (%)	8.55	11.41	12.19	10.35	12.35	9.17	7.17	4.09	11.07
Price/Earnings Ratio	8.42	12.74	11.96	10.16	12.01	12.69	15.15	14.38	14.48
Market/Book Value Ratio	1.29	1.48	1.48	1.36	1.49	1.51	1.47	1.56	1.75

LT = Long term. S&P = Standard & Poor's.

Note: Annual stock prices reflect the average adjusted price for December. Bond rating information was limited for the LDC's. See Appendix C for more information.

Source: Energy Information Administration, Office of Oil and Gas: derived from Standard and Poor's Compustat Services, Inc., "Compustat " database, April 1994.

with pricing provisions linked to the market price is employed but gas prices rise.

A possible step in alleviating some of this supply and price risk might be for LDC's to engage in the futures or options markets to hedge price and volume volatility. To hedge against capacity-shortage risks, LDC's may contract for excess capacity and then try to make use of the capacity release market. However, LDC's face problems with State regulators if their hedging strategies result in purchases of capacity or gas at rates substantially out of line with the market.

Forging New Relationships: LDC's and State Regulators

LDC's are unique in that they are affected by both State and Federal regulations. LDC's have, by State statute, an obligation to provide the public with natural gas. Prior to Order 636, bundled pipeline company costs were usually passed on to the LDC's customers because State public utility commission (PUC) prudency reviews rarely challenged FERC-approved pipeline company rate schedules. However, under Order 636, LDC's will be purchasing unbundled gas, transportation, and storage services. Depending on the service, the rates LDC's pay for these services may no longer

Table 17. Factors Influencing the Financial Performance of Local Distribution Companies

Factor	Description
Unbundling	Local distribution companies (LDC's) are assuming new risks (i.e., supply, price, and capacity risks) by taking on many of the responsibilities formerly performed by pipeline companies–aggregating gas supplies and choosing the right mix of transportation, storage, gathering, balancing, and other services to meet customer needs. Unbundling may allow LDC's to provide new services, however, that are more focused on meeting their customers' needs.
Access to Storage and Peak Shaving	Access to storage is now a crucial determinant affecting the ability of LDC's to maintain reliable and low-cost service. For example, LDC's such as CMS Energy Corporation located near Midwest storage fields may have a comparative advantage over other LDC's with less access to storage and peak-shaving facilities.
Strategic Management	Management strategies adopted during the past few years by LDC's to compete in the restructured gas market have had an important influence on the financial success of these companies. The ability of managers at LDC's to seize the opportunities for new service growth under Order 636, while minimizing the increased risks of doing business in the more competitive environment, will have much to do with the financial success of LDC's in the near future.
Relationships to State Public Utility Commissions (PUC's)	Although Order 636 has resulted in greater regulatory certainty at the interstate/Federal level, significant regulatory uncertainty still exists regarding how State public utility commissions (PUC's) will respond to Order 636. As a result, dialogue with PUC's has never been more important for LDC's. Financial success for many LDC's may hinge on their ability to convince State regulators to be mindful of the new risks LDC's face when the PUC's are setting rates. Preapproval of gas supply and transportation portfolios may reduce the risk of unfavorable prudency reviews.
Reliability	Maintaining reliable service under Order 636 will be more challenging for LDC's. If LDC's establish poor track records in delivering on-demand service, LDC customers may seek to bypass the LDC, getting their service from competing sources. Prior to the 1993-94 winter heating season there was widespread concern among many in the gas industry about the reliability of the restructured industry. In January 1994, that concern was allayed in part because of the success of the distribution companies in meeting their firm capacity requirements despite some of the coldest weather on record affecting the Midwest and the Eastern Seaboard.
Intensifying Competition	Industry restructuring has produced greater competition among gas industry participants in 1993, which has changed the financial outlook for many LDC's. Because of capacity release provisions, many LDC's trying to sell unneeded rights to firm capacity are competing against interruptible transportation/storage services offered by pipeline companies. LDC's also face financial pressure to reduce usage charges paid by their industrial customers to dissuade these customers from hooking up directly to the interstate pipeline mainlines (see Bypass section below). In addition to pipeline companies, some LDC's also compete head to head with marketing companies, whose role in providing restructured gas services is expanding. Ultimately, these competitive pressures may force State PUC's to consider the unbundling of LDC services.
Marketing Released Capacity	Recovery of fixed costs has become a key financial issue for the LDC's because of the adoption of SFV rate design. Participation in the capacity release market may enable LDC's to recover a portion of the higher costs associated with the switch to SFV. Reducing fixed costs associated with unneeded capacity rights will ultimately depend upon how much capacity in the secondary market is discounted. Many LDC's participated in the release market in 1993. Between the official start of Order 636 and April 1994, releases by all end users averaged between 300 million cubic feet and 2 billion cubic feet per week. Releases were typically for a month or less, with the rate of discount ranging from zero to 90 percent.
Mergers and Municipal Pools	To achieve economies of scale in buying gas and transportation services, smaller LDC's have joined together to create municipal pools or cooperatives. By the end of 1993, 15 of these cooperatives had been formed in places like New England, Georgia, and Florida. About 350 municipal LDC's have joined cooperatives so far. Forming these associations gives small LDC's some of the same competitive advantages in securing gas supplies that their larger counterparts already have.
LDC Bypass by Customers	LDC's face an increased risk of bypass by industrial customers. This may occur if LDC's do not offer competitive usage charges or if industrial customers would prefer to obtain service from the pipeline company. Either scenario can be problematic for LDC's because when they lose their industrial customers, they must allocate fixed costs over fewer customers—increasing rates for the remaining customers. The "snowball effect" encourages even more customers to bypass the LDC's.

Sources: **Mergers and Municipal Pools:** Robert S. Caves, American Public Gas Association. **Other:** Energy Information Administration, Office of Oil and Gas.

Table 18. LDC's Shoulder Greater Risks

Type of Risk	Potential Problem	Strategies to Offset Risks
Regulatory Risk	Local distribution companies (LDC's) must now confront a number of regulatory risks. Will they be allowed to pass through all of the transition costs they incur? Will public utility commissions (PUC's) compensate LDC's facing increased risks with higher rates of return? Will PUC's allow LDC's to use financial tools to hedge against price risk? And if the use of these instruments is permitted, under what circumstances will LDC's be allowed to pass through losses or keep gains from participation in risk management activities?	Perhaps the chief way LDC's can minimize their regulatory risk is to maintain an open dialogue with their State regulators. By doing this, LDC's can explain the operational risks they face. At the same time, LDC's can understand more clearly the prudency requirements they will need to meet to get regulatory approval for their actions. In addition, seeking preapproval of their contracting strategies may help LDC's avoid regulatory prudency challenges.
Supply Risk	Because of unbundling, LDC's are now responsible for purchasing their own gas supplies. With this new responsibility, however, comes the associated supply aggregation risks the pipeline companies used to face. LDC's need to make sure that they have sufficient upstream supplies to meet their obligation to serve, even during times of stress (e.g., abnormal weather).	LDC's may reduce their supply risk by adopting several strategies: • Use portfolio contracting. LDC's may want to adopt a portfolio approach to supply contracting by signing a mixture of short-term or spot deals, mid-term (up to 18 months), and long-term contracts. • Diversify supply sources. To enhance post-636 reliability, LDC's may want to buy gas from multiple supply sources as a backstop in case of a *force majeure* event such as a well freezeup or hurricane. • Include supply warranty provisions in contracts. • Strategic use of storage. LDC's may want to use contract storage and peak shaving to improve supply deliverability. • Adopt a load management plan. LDC's may want to normalize their loads to reduce the need to reserve expensive peak gas transportation service.
Price Risk	LDC's need to justify the prudence of the prices in their supply contracts before their State PUC's. If LDC's imprudently enter into supply contracts they face the risk of not being allowed to recover those costs in their rate base.	Some companies, such as Brooklyn Union Gas, have negotiated long-term contracts with "minimum take" provisions. These contracts provide supply reliability, while at the same time enabling LDC's to take advantage of other available lower cost spot-gas supplies. Using these provisions, LDC's have guaranteed delivery of their peak-day requirements, but are not bound to purchasing this quantity throughout the year.
Credit Risk	Many factors influence an LDC's bond rating. Poor bond ratings make it more difficult for LDC's to obtain low-cost capital, which in turn places them at a financial disadvantage. Some LDC's now face increasing credit risk because the investment community does not feel that State regulators will permit LDC's rates of return that are commensurate with new types of risk LDC's are now shouldering.	Maintaining a strong balance sheet, avoiding excessive debt, maintaining market share by marketing new services, and establishing a good working relationship with State regulators are all ways LDC's can improve their bond ratings and facilitate their access to lower cost capital.
Transportation Risk	Making capacity arrangements is more complicated in the post-636 world. For LDC's, decision-making is tougher now because of unbundling and the explosion of new services being offered. Furthermore, when choosing the best mix of transportation services to meet their customers' needs, LDC's must consider explicitly the pricing and the reliability of those services. Meeting their obligation to serve without the pipeline company providing backstop supplies will force LDC's to be more careful how they craft their transportation portfolios.	LDC's can do several things to reduce transportation risk (see Chapter 3): • Adopt a portfolio approach. • Diversify transportation sources. Selecting alternate transportation routes, if possible, can be a hedge against capacity-related curtailments. • Buy rebundled sales service. • Buy no-notice service. • Consult with a firm providing transportation expertise (e.g., marketers, pipeline company marketing affiliates, and management consultants, etc.).

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

be federally regulated. Thus, their purchase practices will be subject to more prudency challenges by State regulators. This will result in increased risk of having some portion of their costs disallowed by the PUC if, for instance, the PUC decides that the LDC overpaid on a supply contract. The same holds true for capacity and storage purchases. The LDC's must absorb these costs if they cannot be passed on to the end users. Additionally, pipeline companies' prudently incurred transition costs are being passed through to LDC's. LDC's will try to pass these costs on to their customers, also raising their rates. State regulators may disallow some of these increased costs, again causing the LDC's to absorb these costs.

A new strategy has been proposed for how LDC's can cope with State regulation in the post-636 era.[89] Under the old "look-back" model, prudency of past purchasing behavior was closely scrutinized using hindsight. In contrast, the new regulatory model posits that a more constructive approach will be a proactive process in which both LDC's and regulators agree up front on the broad parameters that comprise an effective fuel or capacity procurement plan. This plan would emphasize a portfolio of supply and transportation options that would combine short and longer term services as well as firm and interruptible services.

Managing Change

Probably the most important side effect of Order 636 for the LDC's is the need to change management strategies. LDC's face new decisions regarding gas purchasing and marketing strategies. Although Order 636 does not address the issue directly, many LDC's are faced with an enormous task of significantly restructuring the way they operate.

Purchasing Decisions

LDC's will have to adopt innovative approaches in buying fuel and capacity to stay competitive. Purchasing decisions by LDC's are more complicated now because there is a greater variety of services being offered. Key factors LDC's have to take into account in buying services include:

- Quality of service required (firm versus interruptible)
- Time period (short, mid, or long term)
- Availability of gas or capacity
- Diversity of gas or capacity (multiple supply areas or transportation routes).

Marketing Strategies

Given current demand growth projections, marketing services to new customers will be increasingly important for LDC's to remain profitable. LDC management needs to establish new markets and new services to remain competitive with other gas marketers, as well as with other energy industries. LDC's have improved the quality of their service by becoming more customer-focused, in an effort to expand market share. LDC's have also sought out new markets. For example, many LDC's are now actively marketing increased use of natural gas-fueled appliances and cooling and increased use of natural gas to fuel natural gas vehicles; there are now over 800 centralized gas fueling stations in the United States.

Outlook

Market expansion is important for the continued positive outlook for the natural gas industry. Current projections show the consumption of natural gas will grow from 20 trillion cubic feet (Tcf) in 1993 to 22 Tcf in 2000.[90] This growth will stem from environmental and energy policy initiatives that promote gas use, improvements in the reliability and flexibility of the gas transportation and distribution system, and creation of new, customer-focused services. Because much of the growth is expected to be in the electric utility and industrial markets, the ability of the gas industry to respond to the evolving needs of these sectors will be a significant factor in the long-term prospects for the industry. On the supply side, gas supplies are expected to be developed at prices that allow the industry to capture an increasing share of the domestic energy market. Improvements in the technology for finding and developing supplies, better price signals from the wellhead to the burnertip, and higher efficiencies in producing and moving gas are all expected to contribute to the positive outlook.

Market discipline, rather than regulatory discipline, will drive the financial performance of the industry. The biggest changes could be in store for the most heavily regulated segments, the LDC's and the pipeline companies. Increased competition among all the segments is being fueled by more equal access to pipeline transportation and storage facilities under Order 636, greater access to customers through the creation of market hubs, the availability of better price information through the options and futures markets and pipeline company electronic bulletin boards, and the growing proliferation of unregulated and market-priced services. Taking advantage of these factors, companies in all parts of the industry are offering new or "repackaged" services to differentiate themselves from their competitors. As they do this, the functional distinctions between the industry segments are beginning to blur. For instance, the

[89] Natural Gas Supply Association, *New Approaches to State Natural Gas Regulation* (1993).

[90] Energy Information Administration. *Annual Energy Outlook 1994*, DOE/EIA-0383 (94) (Washington, DC, January 1994), p. 70.

recent development of the secondary market for capacity rights now places LDC's and pipeline companies in direct competition for marketing excess capacity.

Recent trends support a cautious optimism regarding the financial outlook for the natural gas industry. For individual gas companies, the new industry structure allows new flexibility for managing their operations, reducing costs, and finding and developing the markets they can serve best. At the same time, the increased complexity of the market over the near term heightens the importance of contracting arrangements, risk management, and the use of electronic information.

Producers—The financial performance of producers will depend on their ability to find and develop new gas reserves at prices that are competitive with oil. While the continued persistence of low oil prices may constrain profitability, the cost reductions in recent years, decline in excess capacity, and the expected growth in gas demand will be positive influences on producers' financial performance. With better access to pipeline and storage capacity, along with a more favorable transportation rate design, producers now have more control over the marketing of their gas to a wider range of customers. Other factors key to their future financial performance will be applying advanced technology to exploit their reserves and diversifying services.

Marketers—Increased revenues and earnings for marketers will depend on their ability to expand and offer more services. Market hubs will increasingly provide access to additional reserves, storage facilities, and other pipeline connections. This will help them serve a wider regional mix of clients, particularly among those LDC's and end users who remain uncomfortable with rebundling their own supply transactions and prefer the accessibility of "one-stop shopping" offered by marketers.

Pipeline companies—With little or no responsibility for gas procurement, the financial performance of pipeline companies now depends mainly on their role as transporters of natural gas. Because of the switch to SFV rate design, most revenues will be earned by selling firm capacity rights. Financial performance will hinge on both attracting new customers and retaining existing customers. Several avenues exist for pipeline companies to achieve these goals: offering new services, discounting transportation rates, improving efficiency through the use of new technologies such as real-time metering and electronic bulletin board systems, and reducing costs.

LDC's—A key financial uncertainty for LDC's is whether they will be able to maintain or increase their rates of return in the face of greatly increased risks and responsibilities. With primary responsibilities for the acquisition and management of supply and transportation services, LDC's now have the opportunity to manage their costs more effectively. To maintain throughput, LDC's may have to develop new markets for their services (e.g., natural gas vehicles and gas cooling), as well as ensure their rates are competitive to maintain their current customer base. Financial tools such as futures and portfolio management may also become more important.

Overall, the opportunities available to the gas industry are greater today than at any time during the past decade. The new structure that has evolved under Order 636 has put the natural gas market in a better position to compete for energy market share. Ultimately, the financial performance of participants in the natural gas industry will be determined by how well they can adapt to the realities of conducting business in the new environment.

Appendix A

Regulation and Legislation

Appendix A

Regulation and Legislation

Introduction

Pipeline open access, wellhead deregulation, and, most recently, the industry restructuring under Order 636 have pushed the natural gas industry into an era of greater reliance on market forces. Conscious of the inefficiencies engendered by heavy regulation in the past (e.g., gas supply shortages in the 1970's that resulted from artificially low wellhead prices), the Federal Energy Regulatory Commission (FERC) has gradually reduced the scope of its regulatory control during the past decade while allowing the industry, for the most part, to be driven by competition.

Federal policies have been increasingly favorable to natural gas in recent years. During 1993, the Administration redirected energy policy to encourage the use of natural gas. Two policy initiatives were developed. *The Climate Change Action Plan*, announced in October, declared the Nation's commitment to reducing greenhouse gas emissions (see box, p. 126). *The Domestic Natural Gas and Oil Initiative*, released in December, contains explicit measures intended to stimulate markets for natural gas and natural gas-derived products (see box, p. 127). Finally, the North American Free Trade Agreement (NAFTA) is expected to promote natural gas trade among the United States, Canada, and Mexico (see box, p. 128).

While at the Federal level, direct intervention in the markets has been reduced, significant legislative, regulatory, and budgetary actions still will have a continuing effect on the industry. For example:

- Environmental regulations and requirements are conducive to the increased use of natural gas, relative to coal and petroleum products. The Administration is supporting its natural gas emphasis with additional funding.

- State regulatory officials are facing difficult decisions as the removal of many regulatory controls at the Federal level requires a review of the impacts at the State level and perhaps corresponding changes in State regulations.

- With the completion of the North American Free Trade Agreement, the institutional arrangements are in place for additional development of a North American market in natural gas.

- Post-Order 636 regulatory issues are on FERC's agenda. The Commission intends to review its policy on natural gas gathering systems and new facility construction.

- In the aftermath of the March 1994 pipeline explosion in New Jersey, pipeline safety requirements will come under increased scrutiny.

There has been increasing concern about the adequacy of research and development programs to achieve the desired increases in gas utilization. In response to these concerns, the Department of Energy appropriation for Fiscal Year 1994 includes $204 million for research and development (R&D), an increase of 78 percent since 1992 (Figure A1). In addition, several research groups are supported by the gas industry. For example, 1994 funding for the Gas Research Institute (GRI), the largest such organization, includes more than $80 million for basic research into natural gas utilization. Other research groups, including the Natural Gas Vehicle Coalition, the American Gas Cooling Center, and the Industrial Gas Technology Commercialization Center, together are expected to allocate between $3 and $5 million to R&D projects in 1994.

The implementation of Order 636 absorbed the attention of both Federal regulators and the industry in 1993. At present, Order 636 is playing out at the State level. Regulators are reviewing and even revising State statutes to account for the effects of Order 636. This appendix discusses the continuing regulatory developments affecting the natural gas industry in the wake of Order 636. Judicial and State developments relating to implementation of Order 636 are addressed first. The appendix then provides an overview of the major items that FERC will be addressing. Developments in 1993 relating to environmental and pipeline safety issues are also discussed. Finally, the appendix summarizes remaining regulatory uncertainty in the industry.

Regulatory Direction After Order 636

Some regulatory aspects of the industry continue to concern the Administration. For example, *The Climate Change Action Plan*

The Climate Change Action Plan

President Clinton and Vice President Gore introduced in October 1993 a strategy to combat global warming, The Climate Change Action Plan. The key goal of the plan is to reduce emissions of greenhouse gases to their 1990 levels by the year 2000. The Administration strategies to achieve this goal include:

- **Regulatory reform to increase natural gas share of energy use.** The Administration efforts will include an investigation of current pipeline construction rules and a review of the rule regarding the secondary market for pipeline transportation. The Department of Energy (DOE) estimates that such FERC actions can result in an additional increase in gas use of 0.37 trillion cubic feet in the year 2000. Increasing natural gas usage is expected to reduce greenhouse gas emissions from projected 2000 levels by 2.2 million metric tons of carbon equivalent (MMTCE).

- **Seasonal gas use for control of nitrogen oxides (NO_x).** The Administration will promote the summer use of natural gas in utility coal and oil plants and in industrial facilities as an innovative, low-cost NO_x reduction strategy. This action should reduce greenhouse gas emissions from projected 2000 levels by 2.8 MMTCE.

- **Commercialization of high-efficiency gas technologies.** DOE will provide cost sharing from 1995 to 1997 for a portion of the cost for demonstrating the effectiveness of high-efficiency gas technologies, such as fuel cells. Fuel cells are an environmentally safe method of producing electricity and a byproduct, thermal energy. This technology is a means of converting the chemical energy of fuel directly into electrical energy without a combustion process. Commercializing high-efficiency gas technologies could reduce greenhouse gas emissions from projected 2000 levels by 0.6 MMTCE.

- **Expansion of the Natural Gas Star program.** EPA will expand this program, which is a public/private partnership, that reduces methane emissions by introducing and promoting cost effective technologies and practices in the natural gas industry. Natural Gas Star was launched in Spring 1993 and has 26 partners. The program provides technical assistance, implementation guidelines, and an information sharing network for gas companies to achieve cost effective emissions reductions. The expanded program targets production, transmission, and distribution companies not currently in the program. Expanding Natural Gas Star is expected to reduce greenhouse gas emissions from projected 2000 levels by 3.0 MMTCE.

Note: The estimates of increased gas usage and reductions in greenhouse gas emissions were developed by DOE's Office of Planning, Policy and Program Evaluation and the Environmental Protection Agency.

proposes additional regulatory reforms at the Federal level including "an investigation of current pipeline construction rules, promulgation of incentive ratemaking guidelines, and a review of rules regarding the secondary market for pipeline transportation."[91] *The Domestic Natural Gas and Oil Initiative* highlights the role of State and Federal cooperation in regulatory reform, seeking reforms that will focus on "improving access to natural gas distribution facilities; boosting the use of natural gas for transportation; and encouraging the removal of subsidies that work against energy efficiency goals, cost-cutting by distributors, and efficient pricing for ... natural gas."[92]

For the industry, there are remaining issues relating to Order 636 which are being addressed this year, including the judicial review of Order 636 and the State response to Order 636. Other issues at the Federal level, while not as sweeping as Order 636, are important for the continuation of the movement toward providing market incentives rather than regulatory incentives. FERC's agenda includes a review of its policies on gathering and facility construction.

[91] *The Climate Change Action Plan*, October 1993, p. 25.
[92] *The Domestic Natural Gas and Oil Initiative*, December 1993, p. 15.

The Domestic Natural Gas and Oil Initiative

In December 1993, the Department of Energy (DOE) announced The Domestic Natural Gas and Oil Initiative, placing a strong emphasis on natural gas. Opportunities for natural gas should increase as the Administration seeks to replace oil imports with domestic natural gas. The initiative outlines numerous actions that address issues such as tax policy, advanced drilling technologies, cost of regulation, and market demand.

The initiative has two key overarching goals: enhancing the efficiency and competitiveness of U.S. industry, and reducing the trend toward higher energy imports. The Administration intends to accomplish these goals through three major strategic activities and their related actions:

Strategic Activity I:

- **Increase domestic natural gas and oil production and environmental protection by advancing and disseminating new exploration, production, and refining technologies.** DOE is targeting research and development to the needs of small oil and gas producers to help achieve this goal. By May 1994, DOE and the Department of Treasury should complete a joint review of tax laws related to advancing and expanding production technologies. DOE also intends to develop guidelines and strategies for natural gas commercialization and a plan to facilitate a broad technology transfer. The Department will provide initial funding, on a cost-shared basis, for a program to increase the availability and application of current information and technology.

Strategic Activity II:

- **Stimulate markets for natural gas and natural gas derived products, including their use as substitutes for imported oil where feasible.** To stimulate markets for natural gas, the physical infrastructure of the industry should be improved. DOE will work with FERC to remove barriers to environmentally sound construction of additional pipeline and storage facilities. DOE will also encourage increased access to existing facilities while accelerating the development and use of advanced technologies in natural gas storage and distribution. DOE and State utility regulators will work together to foster regulatory reforms that seek to:

  - Improve access to natural gas distribution facilities
  - Encourage efficient pricing for natural gas
  - Boost the use of natural gas as a transportation fuel.

Strategic Activity III:

- **Ensure cost effective environmental protection by streamlining and improving government communication, decision-making, and regulation.** The primary goal is to simplify regulations without compromising environmental guidelines. An interagency working group composed of representatives from DOE, FERC, the Environmental Protection Agency, and others will be created to improve coordination of regulatory issues affecting gas and oil supplies. In addition, DOE will work with the States through organizations like the Interstate Oil and Gas Compact Commission, the National Association of Regulatory Commissioners, and Federal land management services to streamline and integrate regulatory programs. The purpose of these efforts is to eliminate duplication in the form of needless paperwork or duplicate permits and hearings.

North American Free Trade Agreement

The North American Free Trade Agreement (NAFTA) provides rules and guidelines for dismantling trade barriers and creating a trilateral free trade area composed of the United States, Mexico, and Canada. NAFTA generally extends the principles of free trade in the Canada-U.S. Free Trade Agreement (FTA) to include Mexico. The agreement provides for the substantially free flow of capital among the three countries and for some mobility of labor in the form of rules governing the temporary entry of business people.

NAFTA will provide opportunities to sell energy and energy-related products to Mexico. Many Mexican tariffs on energy commodities and oil and gas field equipment are being phased out, although slowly. For example, the 10-percent tariff on natural gas will be phased out over a 10-year period, while the 10- to 15-percent tariffs on oil and gas field equipment will be removed over a period of 5 to 10 years. There are three areas that provide the greatest potential for the U.S. natural gas industry in Mexico: exports, provision of energy-related services, and electricity generation.

- **Exports.** NAFTA allows U.S. and Canadian exporters of natural gas to negotiate directly with potential end users in Mexico, with Petroleos Mexicanos (PEMEX) as a third party to the negotiation. In practice, PEMEX will likely purchase the gas directly and then resell it to the end user. This arrangement could inhibit new gas demand because PEMEX, owner of the only gas distribution network in Mexico, may not allow construction of dedicated gas lines from the United States. However, large industrial users, including investors in new electricity capacity, need these dedicated gas lines.

- **Energy-Related Services.** The agreement could promote opportunities for U.S. energy-related services in three areas. First, Mexico opened 50 percent of the large procurement contracts with PEMEX and Comision Federal de Electricidad (CFE) to U.S. and Canadian businesses, and the number of opened contracts will increase to 100 percent by 2003. Second, NAFTA revises the government procurement process to ensure that U.S. and Canadian contract bids receive fair consideration. This revision is a significant contribution to building Mexico's legal infrastructure and therefore is one of the most important parts of NAFTA. Third, Mexico will now allow contracts for oil and gas drilling services to include performance clauses. Under the performance clauses, foreign drilling contractors could earn compensation based partly on the amount of oil or gas discovered, a common practice in other oil markets. Without such incentives, many U.S. firms considered Mexico's contract requirements for drilling services prohibitive.

- **Electricity Generation.** NAFTA could facilitate the supply of gas to the fast growing industrial base in northern Mexico. This new opportunity for gas may also provide investment potential in electricity generation. Mexico's growing environmental concerns could lead to the displacement of residual fuel oil by natural gas. The Mexican government is increasingly concerned with air quality, especially since severe pollution forced parts of Mexico City to shut down in April 1992. However one problem could hinder the growth of gas demand in electricity generation. PEMEX sells high-sulfur residual oil at a lower price than Mexican natural gas on a comparable Btu basis. Electric generating stations and many large industrial users therefore burn residual oil instead of natural gas. Consequently, much of the electric generation sector is not equipped to burn gas. This could stifle demand for U.S. gas imports to Mexico.

Remaining Obstacles to Free Trade

The provisions of NAFTA seem more effective in promoting U.S. energy investments in Mexico than promoting U.S. exports of goods and services. Nonetheless, the agreement is a first step toward complete free trade with Mexico. Several obstacles to free trade in energy still exist:

- Mexico is unwilling to revise its constitutional prohibition against foreign ownership of energy resources.

- The Mexican government maintains the protection of its state monopolies in oil and natural gas, PEMEX, and in electricity, CFE.

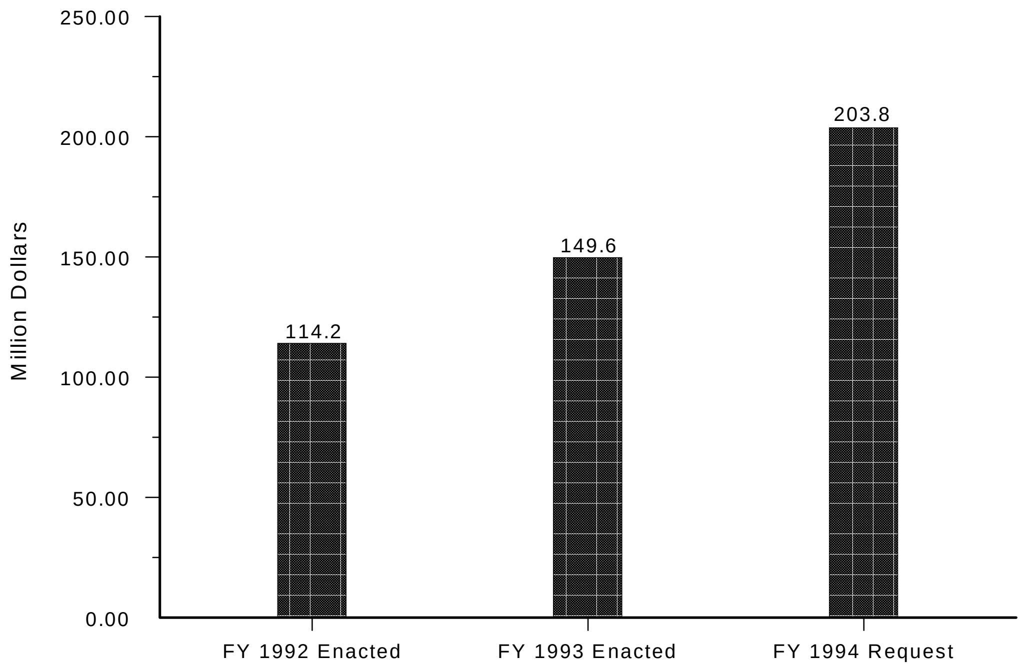
- Mexico still adheres to central planning for the development and use of its energy resources.

- If Mexico decides to restrict its energy production, neither Canada nor the United States will receive any preferential access to that reduced supply.

- The Mexican government reserves the right to sell energy to its domestic market at a lower price than it sells to the United States or Canada.

NAFTA falls short of complete free trade among the three countries. The United States did not win the above concessions it sought during negotiations with Mexico. But NAFTA has chiseled away some of Mexico's antiquated restrictions on trade. The agreement will likely foster increased investment, export, and contracting service opportunities for the U.S. natural gas and oil industries.

Figure A1. DOE Funding for Natural Gas RD&D Programs



RD&D = Research, development, and demonstration.
Source: U.S. Department of Energy, *Natural Gas Strategic Plan and Multi-Year Program Crosscut Plan, FY 1994-1999*, December 1993.

Order 636 Issues

Judicial Review of Order 636

In addition to challenging the Order 636 rule, numerous industry players have appealed certain provisions of the order (as it is applied in the individual pipeline proceedings) to the U.S. Court of Appeals. Until the court decision is rendered, some uncertainty remains regarding the provisions of Order 636. Most objections focus on the legal authority for the restructuring, the change to straight fixed-variable (SFV) rate design, transition costs, and the methods for implementing capacity release. These objections are stated in approximately 100 petitions that comprise the appeal of Order 636, *Atlanta Gas Light Co. and Chattanooga Gas Co. et al. v. FERC*, Nos. 92-8782.

Legal Authority for Unbundling. The legal method used to achieve unbundling has elicited industry criticism. The petitioners of this issue feel that FERC overstepped its authority in restructuring existing NGA Section 7(c) certificates. They state that FERC lacks the authority to split these certificates into sales certificates and transportation certificates.

SFV Rate Design. The SFV rate design has been a controversial provision of Order 636, evoking significant protest from State regulators, LDC's, and consumer advocates. Under the SFV rate structure, fixed costs (which account for 90 to 95 percent of total costs) will be recovered from the reservation charge paid by purchasers of firm transportation capacity. Low load factor customers (typically weather-sensitive customers who use the system primarily during peak periods) may see higher bills as a result of the SFV rate design.

Capacity Release. Another major protest of Order 636 stems from the capacity release mechanism. The petitioners fault the implementation of capacity release. Many LDC's and some State commissions prefer a program in which the pipeline companies are not involved. They argue that pipeline companies could manipulate the program because they have all the information on available capacity.

Transition Costs. Pipeline companies will incur various costs in complying with Order 636. FERC allows pipeline companies to recover 100 percent of "prudently incurred" transition costs. Nearly all (90 percent) of these costs will be recovered from firm transportation customers, while the other 10 percent will be recovered from interruptible transportation customers. Many State public utility commissions (PUC's) and LDC's are appealing the pipeline companies' entitlement to recover 100 percent of prudently incurred transition costs, arguing that the pipeline companies should absorb some transition costs.

The appeal of Order 636 is awaiting judicial review. As of February 1994, the location for the appeal was determined. The Eleventh Circuit Court in Atlanta, originally selected to review Order 636, granted motions for a change in venue to the District of Columbia Circuit Court. But until the judicial review of Order 636 is completed, the risk of court-ordered adjustments remains.

State Response to Order 636

The effect of Order 636 is being felt at the State level, since the unbundling of pipeline services has shifted additional responsibility to gas purchasers for securing their own gas supplies, transportation, and other services, while the change to SFV rate design may affect the prices of these services. Most of the affected purchasers are LDC's and electric utilities who are subject to regulation by PUC's. As a result, many PUC's have been revising, or at least reviewing, their own regulations to take into account the changes in the gas market resulting from Order 636. Thus, the potential for further State-level adjustments in response to Order 636 provides another area of regulatory uncertainty for the natural gas industry.

Many States agree with the underlying philosophy of Order 636. Competition, unbundling, and open access are just some of FERC's goals supported by State regulatory commissions. However, as previously noted, many PUC's object to numerous specific provisions of Order 636. Furthermore, many State commissioners feel that, just as the supply risk has shifted from pipeline companies to LDC's, FERC has also shifted the regulatory burden from the Federal level to the States. The States are responsible for regulating the LDCs' widely expanded role in securing and delivering gas supplies. However, many PUC's feel the implications of Order 636 at the State level are not well understood.

Most State reaction to Order 636 is mixed. Some provisions are considered detrimental while others are viewed as beneficial. In Pennsylvania, the PUC expressed objections to the SFV rate design. The California PUC (CPUC) and the Michigan Public Service Commission (PSC) both voiced opposition to the Order 636 transition cost recovery method.

Although there are several objections to certain aspects of Order 636, most PUC's are developing policies to address or promote some provisions of Order 636. For example the Pennsylvania PUC established policy guidelines to address transition cost recovery (see box, p. 131). In California, the CPUC had already established its own State-level unbundling programs before Order 636 was issued (see box, p. 132). The Michigan regulators dedicated much of 1993 to identifying and examining various State-level issues arising from Order 636 (see box, p. 133).

The FERC Agenda

Gathering Policy

Gathering facilities, generally the smaller diameter pipelines that connect gas wells to a mainline, have been the subject of heated debate for many years. This is because gathering is treated differently than transmission. FERC has some jurisdiction under the Natural Gas Act (NGA) over gathering, but the debate has centered on the scope of that jurisdiction.

The issue became more complex under the industry restructuring, as many pipeline companies have been transferring, or spinning down, their gathering facilities to affiliates, while other facilities have been spun off to nonaffiliates. Many producer and marketer groups are opposed to such facility transfers because of concerns that unregulated gathering firms could exercise market power over production area services and thwart FERC's efforts to enhance competition throughout the industry.

FERC initiated a comprehensive review of its gathering policy in October 1993 (RM94-4). Through the review, FERC sought to clarify the extent of its jurisdiction over rates, terms, and conditions of gathering services provided by interstate pipeline companies and their affiliates. In February 1994 FERC hosted a public conference on gathering to gain further information to determine if regulation of pipeline-affiliate gathering was necessary. Two natural gas industry groups presented the primary opposing viewpoints. Interstate pipeline company representatives argued that natural gas pipeline and affiliate gathering services should be treated like all unregulated gatherers, with no FERC jurisdiction. Large and small gas producers countered that FERC remains legally obligated to exercise its jurisdiction over pipeline companies or pipeline-affiliated gathering operations in order to ensure equal and nondiscriminatory gathering rates.

FERC's New Gathering Policy

In May 1994, FERC's new policy on gathering emerged through the approval of seven orders on gathering decisions. Two of FERC's chief declarations clarify the gathering jurisdiction issue and refine the primary function test, which determines whether pipeline facilities serve as jurisdictional transmission or nonjurisdictional gathering.

Pennsylvania PUC Response to Order 636

Like other States, the Pennsylvania PUC objected to the change to the straight fixed-variable (SFV) rate design mandated in Order 636. It felt that the change harmed firm transportation customers by significantly increasing their demand charges. The Pennsylvania PUC is also involved in the appeal of Order 636.

Although it objects to the SFV provision, the Pennsylvania PUC recognizes the need to deal with other aspects of Order 636. In 1993 the PUC largely focused on transition cost recovery. The PUC issued a proposed policy statement on transition cost recovery in February 1993 and solicited comments on the proposed policy from LDC's, pipeline companies, and others. After consideration of the numerous comments, the PUC issued a Statement of Policy Regarding the Recovery of FERC Order 636 Transition Costs (M00930389) in October 1993.

The Statement of Policy mandates:

- FERC Account 191 transition costs may be presented as a claim in the purchased gas cost proceedings of LDC's subject to the statutory and regulatory procedures applicable to gas cost rate proceedings generally. Account 191 transition costs stem from a pipeline company's pre-Order No. 636 merchant function.

- The cost of new facilities incurred by complying with Order 636 may be recovered through gas cost rate procedures.

- LDC's are allowed the opportunity for the full recovery of gas supply realignment costs and stranded costs by filing a tariff or tariff supplement pursuant to the Pennsylvania Public Utility Code. Stranded costs are those costs associated with facilities that are no longer used and useful after restructuring.

Although the Pennsylvania PUC mostly focused on the task of developing a transition cost recovery mechanism, it also issued a notice of proposed rulemaking (NOPR) to change current intrastate gas transportation tariffs. The NOPR states, "revision of our regulations has become imperative since FERC's restructuring of the national gas industry."

The proposed rule generally strives to minimize "the risk of interstate gas pipeline penalties, gas arbitrage by producers or shippers, and the shifting of cost to retail customers...." The proposed modifications include: strengthening of balancing rules by requiring transportation customers to balance injections and withdrawals within 30 days. Large transporters, shipping more than 100 million cubic feet, may be required to balance no more frequently than daily, while other transporters need to balance no more frequently than weekly. Failure to balance generally will result in the LDC charging out of balance customers for the costs of making up deficiencies, or requiring them to buy excess injection at premium prices. Passthrough of interstate pipeline penalties to transportation customers is not allowed unless the customer's actions directly resulted in the penalties.

The PUC hopes these changes will minimize the possibility that LDC's will incur penalties for violation of interstate pipeline tariffs. Furthermore, the changes should reduce the ability of transportation customers or gas producers to benefit from gas price changes at the expense of LDC's or other customers by "riding" the LDC's system. Transportation rates will be revised to include appropriate administration, demand, and storage costs devoted to transportation.

The Scope of FERC Jurisdiction on Gathering Issues

In the orders, FERC determined that it generally does not have jurisdiction over interstate pipeline companies' gathering affiliates because they are not considered natural gas companies under the NGA. However, FERC retains the right to disregard the separate corporate structures (of the pipeline company and its gathering affiliate) in the event the pipeline company abuses the pipeline-affiliate interrelationship. For example, FERC jurisdiction could be invoked if pipeline transportation discounts were given only to those shippers using the affiliate's gathering service. FERC further declared that pipeline-affiliated gatherers would be subject to State, not Federal jurisdiction, unless abuse of the pipeline-affiliate interrelationship occurs.

To protect shippers from potentially unfair practices, FERC is requiring pipeline companies to demonstrate conformance

California PUC Response to Order 636

The California Public Utilities Commission (CPUC) agrees with FERC's pro-competition philosophy and its open access and unbundling mandates. The CPUC itself has worked for these both in FERC and State proceedings. Recent CPUC regulations include: a rulemaking requiring unbundled services on pipelines and a capacity brokering program for LDC's (basically the same as capacity release), and a rulemaking that encourages large customers to search for the best supply deals.

Although the CPUC supports competition, open access, and unbundling, it objects to two provisions of Order 636. Along with other States, California heavily criticized the straight fixed-variable (SFV) rate design and the transition cost recovery mechanism. The CPUC is active with 14 other States in a joint appeal of these two Order 636 provisions.

In November 1991, the CPUC issued a rulemaking to unbundle interstate and intrastate transportation. By the time FERC issued the final Order 636 in April 1992, two major pipeline companies serving California (Transwestern Pipeline Company and El Paso Natural Gas Company) had largely become gas transporters in response to the CPUC rulemaking. Many of the two pipeline companies' firm bundled service customers were converted to firm transportation service.

The same rulemaking also established a capacity brokering program for LDC's. By November 1993, the California gas utilities, Pacific Gas Transmission and Southern California Gas Company, were already participating in the capacity brokering program. Under the capacity brokering program, the CPUC first determines the amount of capacity LDC's must retain for core customers (predominately residential and commercial customers). Any capacity not needed for core customers can be released. The LDC's must hold an open season to auction off the released capacity to any party wishing to buy it. The open season is nondiscriminatory; whoever bids the highest price, receives the released capacity.

The CPUC has been promoting unbundling and open access at the LDC level since the late 1980's. The CPUC believed large customers should secure transportation and supply agreements more suited to their needs rather than purchase more expensive bundled service.

An Order Instituting Rulemaking issued in September 1990 prohibited LDC's from selling gas supplies to noncore customers; LDC's could only sell transportation service to this sector. The CPUC allowed one exception to this rule. If the noncore customers committed to at least a 2-year supply contract, and paid the same price as core customers, the LDC's could then provide them with gas supplies.

with three standards as a condition to allowing the transfer of facilities. The three standards:

- Require nondiscriminatory access by the pipeline to all sources of supply, and bar undue preference to shippers of a gathering affiliate over shippers of nonaffiliated gatherers in scheduling, transportation, storage or curtailment priority.

- Require disclosure of any information provided to a gathering affiliate in regard to transportation of natural gas, including capacity release or other available capacity, to all similarly situated gatherers in the same basin or field.

- Prohibit the tying of pipeline transportation service to any other service on behalf of, by, or involving the pipeline company's gathering affiliate.

FERC also included another condition to granting facility transfers that applies to both spindowns of pipeline gathering facilities to affiliates and spinoffs to nonaffiliates. Either the pipeline company seeking to transfer facilities or its successor must demonstrate that existing customers served by the gathering facilities have been offered an opportunity to continue service under mutually agreeable terms, conditions, and rates. Should the pipeline company or its successor and existing gathering customers fail to reach an agreement, then the pipeline company or its successor must submit a "default" contract that has been offered to existing customers. The terms for service under the default contract should be consistent with the terms, conditions, and rates for various services currently offered by independent gatherers in the particular region. If FERC concludes that the default contract meets these criteria, it will allow the pipeline company to transfer the facilities.

Michigan PSC Response to Order 636

The Michigan Public Service Commission (PSC) is reviewing several issues arising from Order 636 that affect LDC's and their consumers. The concerns focus on transition costs, storage issues, and gas cost recovery.

The Michigan PSC is dealing with transition cost issues on the Federal and State level. On the Federal level, the PSC is examining the types and amount of transition costs and is involved in the appeal of Order 636's treatment of transition costs. Michigan, like California, also objects to the lack of cost sharing among different transportation buyers. The PSC believes the firm transportation customers bear too much of the transition cost burden.

At the State level, Michigan is evaluating the allocation of transition costs among LDCs' sales and transportation customers. The PSC is also considering whether LDC's should absorb some of the costs. Michigan will likely address these issues in individual LDC rate cases. The PSC notes that a certain precedent exists in its earlier decisions on the passthrough of take-or-pay costs. Transition cost decisions depend on many case-specific factors and therefore a generic PSC policy is impractical.

With approximately 13 percent of U.S. storage capacity, the treatment of storage is another concern for the Michigan PSC. The commission is examining existing and new gas storage facilities. For existing storage, the PSC concerns include:

- Allocation of storage capacity between firm customers and interruptible customers
- Pricing of storage capacity
- Sufficiency of storage capacity.

For new storage the PSC is considering the following issues:

- Encouragement of new natural gas storage
- Jurisdictional role in the development of new storage fields
- Pricing of new storage: rolled-in, incremental, cost-based, or market-based.

The third significant issue facing the Michigan PSC is gas cost recovery (GCR). A few of the concerns center around: soundness of natural gas suppliers, price indexing of supply contracts with producers, and the LDCs' ability to rebundle pipeline services. Michigan will likely address these concerns on a case-by-case basis as more is known about them. These issues depend on many case-specific factors and thus a generic PSC policy is considered impractical.

Revision of the Primary Function Test

Two of the seven orders approved at FERC's May 1994 open meeting addressed the primary function test.[93] FERC declared that facilities located beyond a processing plant, other than those incidental to the plant's operation, will be considered jurisdictional transmission facilities generally. Certain exceptions may be allowed however. In addition to owning facilities behind the processing plant, some gatherers also may own relatively lengthy facilities beyond the plant. These downstream facilities could be exempt if the length is proportional to the length of the gatherer's behind-the-plant facilities. For example, if a gatherer has large facilities behind the processing plant, then large facilities beyond the plant may be necessary as an incidental extension of either plant operations or the gathering system located behind the plant. FERC would then classify the facilities beyond the plant as gathering, rendering them exempt from jurisdiction.

Facility Construction

Order 555 (RM90-1-00, September 1991), the construction rule, was intended to provide comprehensive guidance on construction projects. However implementation of the order was postponed in November 1991 because of numerous industry objections to certain provisions. Instead, FERC continues to issue construction certificates on a case-by-case basis.

Under Section 7(c) of the NGA, FERC has authority over the construction of new pipeline facilities or the expansion of existing systems. FERC approves a specific construction project and rules on another crucial issue: the cost recovery method for the new facility.

For several decades, FERC policy was mainly shaped by the Kansas Pipe Line test.[94] This test established the minimum requirements necessary to ensure protection of the public while encouraging expansion of service where needed. The Kansas Pipe Line test required the construction certificate applicant to meet seven criteria. Some of these standards were later modified by FERC Order 555. Although Order 555 was vacated in November 1991, FERC continues to apply some of the modified criteria, where the applicant has not met the Kansas Pipe Line analysis.

[93]The primary function test is a set of standards used by FERC to determine whether a facility's primary function is transmission or gathering. These standards include diameter, length, location, and operation pressure of the line. FERC modified the primary function test to account for the changing technical and geographical nature of exploration and production, especially for offshore facilities. Under the modified primary function test, FERC applies a sliding scale that allows pipeline lengths and diameters to increase in correlation to the distance from the shore and water depth of an offshore production area.

[94]*Kansas Pipe Line and Gas Company, et al*, 2 FPC 29 (1939).

The Kansas Pipe Line market standard required the applicant to prove that "there exist customers who can reasonably be expected to use the proposed natural gas service." Under this standard, an applicant was required, prior to the time construction commenced, to have executed firm contracts and supporting market data demonstrating that present and future rate payers will be protected from having to make inappropriate contributions to the costs associated with the new facilities. Absent such showing, FERC will place the applicant at risk for any underutilization of facilities.

FERC currently continues to issue at-risk certificates. The purpose of these certificates is to prevent shifting the costs of underutilized facilities to existing customers who derive minimal benefits from the new project. In addition, at-risk certificates should guard against unwarranted rate increases to customers who use the new facilities in the event the new capacity is substantially underused. FERC has reasoned that the pipeline company is in the best position to evaluate the need for facilities and should shoulder the risk of misjudgment.

The pipeline company can subsequently seek removal of the at-risk terms and conditions imposed on the new facilities in a general rate case filed under Section 4 of the NGA. FERC has indicated that it would not impose a rigid formula. Instead, pipeline companies are free to demonstrate in the Section 4 proceeding that the costs of the facilities sought to be included in rates would result in just and reasonable rates for its customers. The pipeline company will have the burden to show that FERC's concerns about unwarranted cost shifts to existing customers or unwarranted cost increases to the project's customers are satisfied.

Commencing construction of a new facility under an at-risk certificate is a large gamble for a pipeline company. The cost recovery method, or future rate treatment, for the new facility is unknown. FERC determines a rate treatment at the time of certification but this can be reversed in a later rate case. As a result, financial arrangements are difficult to make. For example, a pipeline company may be unable to secure loans for building the new facility because potential lenders have no way of knowing how the pipeline company will recoup the new facility's cost.

In addition, FERC's policy on the cost recovery method for new facilities has changed. The issue is rolled-in versus incremental rate treatment (rates are designed using the straight fixed-variable (SFV) method). Previously, FERC was inclined to allow rolled-in rates. Under this rate treatment, FERC permitted the pipeline company to recover the new facility's costs from the established systemwide rate base.

Both existing shippers and shippers who would use the new facility, or expansion shippers, would pay the costs through their rates. With at-risk certificates, FERC changed its preference in cost recovery. In most cases, when an at-risk certificate is issued, costs would be recovered only from the rates charged to expansion shippers, known as incremental rates. Under this method, the recovery of costs is less certain. The expansion shippers may underutilize the new facility, or the pipeline company may not secure enough expansion shippers to meet the capacity.

FERC has not revisited the facility construction issue because it had focused on Order 636 compliance filings during 1993. Now that the restructured pipeline industry is operating, the Commission will probably return to facility construction policy. Chair Moler has hinted on the direction of FERC's policy. In an address to the 1993 North American Natural Gas Summit, she stated that an at-risk decision is necessarily an interim one because the Commission cannot determine in advance if the new capacity will be "used and useful."

Incentive Regulation

Many of the risks in the interstate pipeline industry could change by moving away from the traditional cost-of-service regulation to incentive regulation. Under the cost-of-service approach, rates are set at a level that is expected to generate enough revenues to allow the firm to recover its expenses plus an allowed return on assets. Cost-of-service regulation, which has also been widely applied to other regulated industries, has been severely criticized for its failure to provide firms with incentives to operate efficiently. One criticism is that a firm's costs may be accepted by regulators as being "just and reasonable" when in fact more efficient operations could reduce costs. Another criticism is based on the Averch-Johnson hypothesis.[95] This theory argues that regulated firms have an incentive to overinvest in capital because allowed profits are set as a percentage of their capital assets.

As a result of these shortcomings of cost-of-service regulation, some regulators of other industries, as well as State public utility commissions and FERC, have begun to consider alternative forms of regulation, known collectively as "incentive regulation." Incentive regulation tends to simulate competition in a monopoly environment by tying utilities' returns to performance. For example, utilities may be allowed to retain as profit a portion of any cost saving they are able to achieve. This gives them an incentive for further cost reductions. Customers would receive any remaining cost savings in the form of reduced rates. In contrast, under cost-of-service regulation, cost savings eventually result in a reduction in the cost basis of the utility and are passed through to consumers in the form of lower rates. However, the passthrough of cost savings does not happen until the pipeline company files its next NGA Section 4 rate case or FERC initiates a Section 5 rate proceeding. With incentive rates, public utilities receive incentives similar to firms in a competitive market. A utility is rewarded for minimizing costs because it retains a portion of the cost savings. However, should the utility make a poor decision, both the customers and the utility may forego the opportunity for reduced rates and higher returns, respectively.

In October 1992, FERC issued a policy statement on incentive ratemaking, establishing guidelines for companies to use in formulating incentive proposals. The policy statement provides only general principles for utilities interested in filing for incentive regulation. The individual companies must develop specific incentive ratemaking proposals. Pipeline companies and LDC's have acknowledged the benefits of incentive regulation. But because Order 636 affected most segments of the natural gas industry, much of the industry's efforts concentrated on issues related to restructuring in 1993.

Some utilities, primarily LDC's, have begun to examine the possible use of incentive rates. Most LDC's incentive rate plans are currently in an experimental stage. However one LDC, San Diego Gas and Electric (SDG&E) in California, implemented an incentive rate plan in 1993 for gas purchasing (in California these rates are termed performance-based rates). SDG&E's performance-based rate plan involves two components. The first component measures SDG&E's purchasing performance at the mainline against an established benchmark cost. By improving efficiency and using risk management tools, SDG&E may lower its costs below the benchmark cost. The resulting savings, expressed in the form of lower rates to customers and higher rates of return to stockholders, are shared equally. Similarly if the cost of the gas is greater than the benchmark (plus 2 percent), SDG&E's customers and stockholders absorb these costs through higher rates or lower rates of return. The second component compares the price SDG&E pays at the citygate (gas cost plus transmission cost) to the benchmark. If the citygate price is less than the established benchmark, 95 percent of the savings go to SDG&E's customers and 5 percent of the savings go to the stockholders.

At present, LDC's are more active in developing incentive rate programs than interstate pipeline companies. For example, some State utility commissions, such as in Maryland, are currently examining the advantages of using incentive rates. Other States have gone even further. The New Jersey Board of Regulatory Commissioners reviewed a formal LDC incentive rate proposal in 1993, but the proposal was later withdrawn. Although FERC adopted the policy statement on incentive ratemaking proposals, no pipeline companies are using incentive rates at this time. However, FERC approved market-based rates for several companies in 1993.

[95]Harvey Averch and Leland Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review*, 52 (1962), pp. 1052-1069.

Environmental and Safety Developments

During 1993, some notable environmental programs, regulation, and legislation were implemented. The Environmental Protection Agency (EPA) introduced new programs and policies that will affect the natural gas industry. The Department of Interior (DOI) also announced regulation that is likely to have an impact on the industry. In addition, EPA, DOI, the Department of Energy (DOE) and others are pursuing interagency approaches to the environmental goals of the Administration. For example, in November 1993, EPA announced the Green Sectors Program. The program is designed specifically to work with selected industries, State regulators, and other stakeholders to improve the environmental results and reduce the economic impact of EPA programs.

In March 1994, a natural gas pipeline explosion in Edison, New Jersey prompted increased public attention on the safety of natural gas pipelines. The blast destroyed an apartment complex and displaced several hundreds of people. Many Federal and State officials called for a review of safety procedures for pipelines as a result of the explosion.

The Department of Transportation's (DOT) Research and Special Programs Administration (RSPA) is responsible for regulating oil and natural gas pipelines for safety. When an accident occurs, pipeline companies must file accident reports with this agency. RSPA is also responsible for implementing safety legislation, such as the Pipeline Safety Act of 1992.

Environmental Developments

Seasonal Fuel Switching

The EPA announced that electric utilities and industrial boilers can now switch to natural gas in the summer in order to meet Clean Air Act requirements. This new policy could increase natural gas demand in the summer, at least over the long term. The policy allows for switching to cleaner fuels during the summer, when ozone is a problem and gas is available. Previously, EPA required continuous emissions controls throughout the year. This typically involved combustion equipment modifications such as installation of low nitrogen oxide burners. Utilities and industrial boilers can now average summer and winter emissions under the new policy to achieve an annual target. EPA concluded that in many cases, fuel switching will be a more cost-effective method for controlling nitrogen oxide emissions than traditional add-on controls.

PCB Contamination

For the first time, EPA addressed abandoned local distribution pipelines, contaminated with PCB's. Regulations have been in place for some time, but were not applied to local distribution lines. PCB's were historically used as lubricants at pipeline-related facilities. They were later discovered to cause cancer.

Included in the regulations is an American Gas Association (AGA) proposal that distributors maintain an inventory of the contaminated, abandoned pipelines and mark their location. EPA may call for distributors to fill contaminated pipes, destined for abandonment, with fly ash or other inert material to render them unusable. The agency is concerned that excavators may unearth the pipeline and be exposed to the PCB's. EPA is further troubled by the possibility of contaminated pipes being removed and then used for another purpose.

EPA's allowance of PCB-contaminated pipelines to remain in the ground is unprecedented. This remedy is part of an evolving view at the agency that recognizes hazardous material is best left undisturbed in some cases.

Pollution Discharge

In March 1993, EPA developed the National Pollution Discharge Elimination System (NPDES) guidelines under Title III of the Clean Water Act for the control of discharges from offshore oil and gas facilities. NPDES permits have mandated zero discharge of produced water in some regions of the country. Members of the natural gas industry have expressed concerns that these restrictions place considerable cost burden on producers and have questionable environmental benefits.

Oil Pollution Act

Under the Oil Pollution Act, the Minerals and Management Service of the DOI issued a Notice of Proposed Rulemaking that would require onshore and offshore oil and gas facilities to demonstrate the ability to pay up to $150 million for potential pollution damages. This requirement could have a significant impact on the operation of many small natural gas producers and storage operators.

Pipeline Safety

The RSPA regulates both oil and gas pipelines from the wellhead to the burnertip, including interstate and, through State cooperation, intrastate lines. The agency also tracks statistics on pipeline accidents. During 1991, the latest year for which data are available, natural gas transmission and gathering pipeline operators reported 71 incidents, involving 12 injuries and $11,706,237 in property damage.[96] An incident involves a release of gas and either: (1) a death or personal injury necessitating in-patient hospitalization or (2) estimated property damage of $50,000 or more. Natural gas distribution pipeline operators reported 162 incidents, involving 14 deaths, 77 injuries, and $7,813,748 in property damage. Of the 233 total gas incidents, 139 (60 percent) were attributed to damage by outside forces.

Although pipeline safety recently became a highlighted concern of the general public, it has been a concern of legislators for some time. Lawmakers passed a major piece of legislation, the Pipeline Safety Act in 1992. RSPA is responsible for implementing the provisions of the legislation. Three critical provisions of the act affect the natural gas industry:

- New and replacement oil and gas pipelines are required to accommodate internal inspection devices, called smart pigs. Smart pigs are electronic devices that are sent through the pipeline to inspect for structural weaknesses.

- Existing oil and gas pipelines in high density population areas are required to undergo periodic inspection.

- Excess flow valves are required only for residential properties to shut off excess gas flow; they are similar to an electrical fuse. The valves will be placed at the curb of a house to regulate the gas lines leading into the house.

- There are roughly 7.5 million miles of customer-owned pipelines in the United States. Natural gas utilities are required to inform customers of the pipelines they own. The utilities must also advise customers on pipeline maintenance and the hazards of failing to maintain pipelines.

In April 1994, RSPA issued a Final Rule that implements a program for the first of the above provisions, the use of smart pigs in new and replacement pipelines. The agency is also expected to issue another Final Rule for the second provision, requiring the periodic inspection of existing pipelines, in October 1995.

Summary

During the past 15 years, regulatory change has directed a new approach to doing business in the natural gas industry. The purchase and sale of natural gas at the interstate level are now driven by market conditions with no regulatory interference.

The most significant area of regulatory uncertainty now rests in the State arena. Although State regulatory authorities are supportive of many aspects of Order 636, they face difficult decisions regarding the appropriate allocation of costs associated with restructuring among customer classes. The cumulative costs associated with the industry restructuring during the past decade have resulted in the passthrough or pending passthrough of $17 to $19 billion to consumers.[97] While the change in rate structure mandated in Order 636 often results in residential and commercial customers paying an increased share of the LDC's costs of providing that service, lower rates to customers with fuel-switching capabilities may be necessary to keep them on the system and contributing to the reduction of overall system costs.

The State PUC's are also evaluating the extent to which the unbundling provisions of Order 636 should be extended to the distribution system within their States. One State, California, has already adopted that approach.

[96]Department of Transportation, Office of Pipeline Safety, *Annual Report on Pipeline Safety Calendar Year 1991* (Washington DC, 1991), p. 21.

[97]These costs include take-or-pay settlement costs of $11 billion to $13 billion, transition costs of $4.8 billion, and SFV rate change cost shifts of $1.2 billion. Take-or-pay costs are Energy Information Administration estimates based on FERC Order 636-B. Transition costs are from the Government Accounting Office, *Report on the Costs, Benefits, and Concerns Related to FERC's Order 636* (Washington, DC, November 1993).

Appendix B

Transportation Rates Under Order 636

Appendix B

Transportation Rates Under Order 636

This appendix contains numerical examples of transportation rates, as discussed in Chapter 2, for a hypothetical pipeline company (Pipeline A) using the straight fixed-variable (SFV) rate design. It also includes examples showing the impact on rates of interruptible revenue crediting, capacity release, and transition costs. The examples are intended to show, in a greatly simplified fashion, how firm and interruptible rates are developed from a pipeline's company's cost and throughput characteristics.

The examples are all based on a common set of assumptions about Pipeline A's costs and operations (Table B1). The company is assumed to have total fixed costs of $900 million, variable costs of $20 million, and expected throughput of 1,200 trillion Btu (TBtu), of which 1,000 TBtu is expected to be firm service and 200 TBtu interruptible. The system load factor (average daily demand divided by peak-day demand) is assumed to be 0.33, which gives a maximum peak-day demand for firm service of 8.302 TBtu.

Table B1. Cost and Operating Assumptions for Pipeline A

AA	Total System Fixed Costs (million dollars)	$900
AB	Total System Variable Costs (million dollars)	$20
AC	Firm Throughput (TBtu)	1,000
AD	Interruptible Throughput (TBtu)	200
AE	System Load Factor (average/peak)	0.33
AF	Transportation Contract Term (months)	12
AG	Peak Period (months)	3
AG'=AG*30	Peak Period (days)	90
AH	Off-Peak Period (months)	9
AH'=365-AG'	Off-Peak Period (days)	275
AI	Allowed Return on Rate Base (percent)	11
AJ	Cost of Debt (percent)	9
AK	Income Tax Rate, Combined State and Federal (percent)	38
AL	Depreciation Rate for Rate Base (percent)	5
AM	Ad Valorem Tax Rate (percent)	2
AN	Debt/Equity Ratio	50/50
AO=AC+AD	Total Throughput (TBtu)	1,200
AP=AC/365/AE	Peak Firm Capacity (TBtu)	8.302

Note: Row names begin with A to designate the "Assumptions" table.
Source: Energy Information Administration, Office of Oil and Gas.

The financial structure of the firm is assumed to be equally divided between debt and equity. The allowed return on rate base is 11 percent; the cost of debt is 9 percent. State and Federal income taxes amount to 38 percent of the sum of return on equity and income tax liability. In addition, there is an ad valorem tax of 2 percent of the value ofthe rate base. The rate base is depreciated over a 20-year period, giving an annual depreciation rate of 5 percent.

SFV Rate Design

SFV rates are determined on the basis of cost and operating characteristics (Table B2). Variable costs are recovered from all customers through the usage fee of $0.017 per million Btu (MMBtu), which is derived as shown in Equation (1):

$$\begin{aligned} \text{Usage Fee} &= \text{Variable Costs / Total Throughput} \\ &= \text{\$20 million / 1,200 TBtu} \\ &= \text{\$0.017/MMBtu} \end{aligned} \tag{1}$$

Table B2. SFV Rate Calculations

RA=AC/365/AE+AD/365	Reservation Fee Billing Units (TBtu)	8.85
RB=AO	Usage Fee Billing Units (TBtu)	1,200
RC=AA*AP/RA	Fixed Costs Allocated to Firm Customers (million dollars)	$844
RD=AA*AD/365/RA	Fixed Costs Allocated to Interruptible Customers (million dollars)	$56
RE=AA/RA/12	Monthly Reservation Fee ($/MMBtu)	$8.47
RF=AB/RB	Usage Fee ($/MMBtu)	$0.017
RG	Assumed Interruptible Load Factor	1
RH=RE*12/(365*RG)+RF	Maximum IT Rates ($/MMBtu)	$0.295
RI=RF	Minimum IT Rates ($/MMBtu)	$0.017
RJ=RE*12*AP/AC+RF	Average Cost of Firm Throughput ($/MMBtu)	$0.861

Note: Row names begin with R to designate the "Rate" table. IT = Interruptible Transportation.
Source: Energy Information Administration, Office of Oil and Gas.

Fixed costs are recovered from both firm and interruptible customers. Fixed costs recovered from firm customers are based on the peak day capacity reservation. Fixed costs recovered from interruptible customers are based on average interruptible throughput adjusted for discounting and the rate design load factor. The total reservation billing units over which fixed costs are spread therefore consist of 8.302 TBtu of peak firm capacity and 0.548 TBtu of imputed reservation billing units for interruptible transportation (assuming no discounting and a 100 percent interruptible rate design load factor):

$$\begin{aligned} \text{Reservation Fee Billing Units} &= \text{Peak Firm Capacity Reserved} \\ &\quad + \text{Average Daily Interruptible Throughput} \\ &= \text{8.302 TBtu + (200 TBtu / 365 days)} \\ &= \text{8.85 TBtu} \end{aligned} \tag{2}$$

Thus, in this example, firm customers are responsible for 93.8 percent of total fixed costs ($844 million) while interruptible customers are responsible for the remaining 6.2 percent ($56 million).

The monthly reservation charge is calculated by first converting fixed costs to a monthly basis and dividing by the number of reservation fee billing units, as shown in Equation (3):[98]

$$\text{Monthly Reservation Fee} = \$900 \text{ million / 12 months / 8.85 TBtu} \quad (3)$$

$$= \$8.47\text{/MMBtu}$$

Both minimum and maximum interruptible transportation (IT) rates are calculated. The minimum IT rate is equal to the firm usage fee. The maximum IT rate is determined as shown in Equation (4):

$$\text{Maximum IT Rate} = \text{Annualized Reservation Fee / (365 days * Interruptible Load Factor)} + \text{Usage Fee} \quad (4)$$

$$= \$8.47\text{/MMBtu * 12 months / (365 * 1.0) + } \$0.017\text{/MMBtu}$$

$$= \$0.295\text{/MMBtu}$$

Interruptible Revenue Crediting

The interruptible revenue crediting mechanism is an interim measure designed to permit pipeline companies to make conservative estimates of interruptible volumes until actual experience with capacity release provides a basis for more accurate estimates of interruptible throughput. One effect of interruptible revenue crediting may be to reduce firm transportation (FT) rates (Table B3).

In its SFV rates (Table B2) the company would recover $56 million of fixed costs from interruptible service. However, if the company is able to sell more interruptible service than it projects, it may recover more than the allocated $56 million. The overrecovery represents profit for the company. The revenue crediting mechanism requires the pipeline company to distribute 90 percent of the overrecovery to firm customers, thereby reducing their rates, and keep only 10 percent as profit for the company.

Suppose interruptible throughput is twice as much as expected—400 TBtu rather than 200 TBtu. Then, at the maximum IT rate, the pipeline company's revenues will be $59 million higher than expected:

$$\text{Incremental IT Revenues} = \text{Incremental IT Throughput * Maximum IT Rate} \quad (5)$$

$$= 200 \text{ TBtu * } \$0.295\text{/MMBtu}$$

$$= \$59 \text{ million}$$

After deducting the $3.4 million variable cost of transporting the additional gas (i.e., the 200 TBtu of incremental throughput times the usage fee of $0.017, which is the per-unit variable cost of service), the pipeline company retains 10 percent of the remainder ($5.6 million) as profit and credits 90 percent ($50.0 million) to firm customers:

$$\text{Incremental Pipeline Profit} = 0.10 \text{ * (Incremental IT Revenues - Incremental Cost)} \quad (6)$$

$$= 0.10 \text{ * (}\$59 \text{ million - 200 TBtu * } \$0.017\text{/MMBtu)}$$

$$= \$5.6 \text{ million}$$

$$\text{Firm Customer Credit} = 0.90 \text{ * (Incremental IT Revenues - Incremental Cost)} \quad (7)$$

[98]Alternatively, the reservation fee can be calculated by converting the firm fixed costs ($844 million) to a monthly fixed cost ($70.3 million) and then dividing by the firm peak-day capacity or 8.302 TBtu.

= $50 million

This reduces the revenue requirement for fixed costs from firm customers to $794 million (from the original $844 million):

Revised Firm Customer Revenue Requirement	=	Original Firm Customer Revenue Requirement - Firm Customer Credit	(8)
	=	$844 million - $50 million	
	=	$794 million	

which reduces the effective monthly reservation fee to $7.97/MMBtu (from $8.47 originally):

Effective Monthly Reservation Fee	=	Revised Firm Customer Revenue Requirement / Peak Firm Capacity / 12 months	(9)
	=	$794 million / 8.302 TBtu / 12 months	
	=	$7.97/MMBtu	

The example assumes that the incremental interruptible throughput was charged the maximum IT rate. If a discounted rate were charged, the revenue impacts would be smaller. In the case of a discounted IT rate at 50 percent of the maximum rate, the reservation fee would be reduced to only $8.23/MMBtu (Table B3).

Table B3. Interruptible Revenue Credit Calculations

IA	Crediting Factor	0.9
IB=AD	Interruptible Throughput (TBtu)	200
IC	Incremental Interruptible Throughput (TBtu)	200
ID=IB+IC	Adjusted Interruptible Throughput (TBtu)	400
Case 1: Incremental IT Sold at Maximum IT Rate		
IE=IC*RH	Incremental IT Revenues (million dollars)	$59.0
IF=IC*RF	Cost to Pipeline (million dollars)	$3.4
IG=(IE-IF)*IA	Firm Customer Credit (million dollars)	$50
IH=(IE-IF)*(1-IA)	Incremental Pipeline Profit (million dollars)	$5.6
II=(RE*12*AP-IG)/AP/12	Effective Reservation Fee ($/MMBtu)	$7.97
Case 2: Incremental IT Sold at 50% of Maximum IT Rate		
IJ=0.5*IE	Incremental IT Revenues (million dollars)	$29.5
IK=IF	Cost to Pipeline (million dollars)	$3.4
IL=(IJ-IK)*IA	Firm Customer Credit (million dollars)	$23.5
IM=(IJ-IK)*(1-IA)	Incremental Pipeline Profit (million dollars)	$2.6
IN=(RE*12*AP-IL)/AP/12	Effective Reservation Fee ($/MMBtu)	$8.23

Note: Row names begin with I to designate the "Interruptible Revenue Credit" table. IT = Interruptible Transportation.
Source: Energy Information Administration, Office of Oil and Gas.

Capacity Release

Holder(s) of firm pipeline capacity rights can reduce their transportation costs by releasing capacity (Table B4). For simplicity, assume that Pipeline A's firm capacity is all held by a single shipper. That shipper will transport 1,000 TBtu of gas over the course of a year (Table B1). However, its capacity needs will vary greatly throughout the year. During a 3-month (90-day) peak period the shipper will need 8.302 TBtu of capacity. Total throughput during the peak period will therefore be 8.302 TBtu * 90 days = 747 TBtu. The remaining 253 TBtu of firm throughput will be transported during the remaining 9 months (275 days) of the year. This means that the average daily firm capacity needed during the off-peak season is only 253 TBtu / 275 days = 0.919 TBtu.

Table B4. Cost Impacts of Capacity Release

CA=AC/365	Average Firm Capacity Need (TBtu)	2.740
CB=(AC-AP*AG')/AH'	Off-Peak Firm Capacity Need (TBtu)	0.919
CC=AP-CB	Off-Peak Excess Capacity (TBtu)	7.383
CD=CC*AH'	Yearly Off-Peak Excess Capacity (TBtu)	2030
CE=RC	Total Yearly Firm Capacity Cost (million dollars)	$844
CF=CE/AP/365	Average Cost of Reserved Firm Capacity ($/MMBtu)	$0.279
CG=CE/AC	Average Cost of Firm Capacity Used ($/MMBtu)	$0.844
CH=CF*CD	Yearly Cost of Excess Capacity (million dollars)	$566
Case 1: Capacity Release at Full Reservation Fee		
CI=CC	Released Capacity (TBtu)	7.383
CJ=AH	Release Period (months)	9
CK=CI*RE*CJ	Total Revenues from Capacity Release (million dollars)	$563
CL=CE-CK	Net Cost of Total Capacity to Releasing Shipper (million dollars)	$281
CM=CL/AC	Average Cost of Capacity to Releasing Shipper ($/MMBtu)	$0.281
CN=CL/12/AP	Effective Monthly Reservation Fee ($/MMBtu)	$2.82
Case 2: Capacity Release at 50 Percent of Reservation Fee		
CO=0.5*CI*RE*CJ	Total Revenues from Capacity Release (million dollars)	$281
CP=CE -CO	Net Cost of Total Capacity to Releasing Shipper (million dollars)	$563
CQ=CP/AC	Average Cost of Capacity to Releasing Shipper ($/MMBtu)	$0.563
CR=CP/12/AP	Effective Monthly Reservation Fee ($/MMBtu)	$5.65

Note: Row names begin with C to designate the "Capacity Release" table.
Source: Energy Information Administration, Office of Oil and Gas.

The shipper must permanently reserve capacity to meet its peak needs of 8.302 TBtu even though this level of capacity will only be needed for 3 months out of the year. In this example, the shipper must reserve 3,030 TBtu of annualized capacity (8.302 TBtu of peak capacity * 365 days) even though the annual firm throughput is only 1,000 TBtu. At a monthly reservation charge of $8.47 per MMBtu, the total cost of firm capacity will be $844 million per year. When averaged over the annualized capacity reservation of 3,030 TBtu, this gives a per-unit capacity cost of $0.279 per MMBtu:

Per-Unit Cost of Firm Capacity Reserved	=	Annualized Reservation Charge / Annualized Capacity Reserved	(10)
	=	$8.47/TBtu * 8.302 TBtu * 12 months / (8.302 TBtu * 365 days)	
	=	$844 million / 3,030 TBtu	
	=	$0.279/MMBtu	

However, the shipper will not need much of this capacity during the year. Since a total of only 1,000 TBtu of gas will actually be shipped during the year, the per-unit transportation cost (i.e., the average cost of capacity actually used) is $0.844/MMBtu.

Per-Unit Cost of Firm Capacity Used	=	Annualized Reservation Charge / Annual Firm Throughput	(11)
	=	$844 million / 1,000 TBtu	
	=	$0.844/MMBtu	

Now suppose the shipper is able to take full advantage of the capacity release program to resell its unneeded capacity at the pipeline company's maximum rate for firm transportation—i.e., the monthly reservation charge of $8.47/MMBtu. The unneeded capacity is available in the off-peak season (9 months) when the shipper has reserved 8.302 TBtu but only needs 0.919 TBtu. This leaves 7.383 TBtu of releasable capacity. If this is sold at the full reservation fee, the releasing shipper will earn $563 million in revenues—recovering the full cost of the excess capacity:

Total Revenues from Capacity Release	=	Released Capacity * Release Period * Reservation Fee	(12)
	=	7.383 TBtu * 9 months * $8.47/MMBtu	
	=	$563 million	

This will reduce the releasing shipper's effective total cost of capacity from $844 million to $281 million, for an effective per-unit capacity cost of $0.281/MMBtu:

Average Cost of Capacity to Releasing Shipper	=	(Total Cost of Capacity - Revenues from Capacity Release) / Annual Firm Throughput	(13)
	=	($844 million - $563 million) / 1,000 TBtu	
	=	$0.281/MMBtu	

This average capacity cost corresponds to an "effective" reservation fee of $2.82/MMBtu (Table B4).

The total levelized firm transportation cost consists of the average cost of capacity plus the usage fee—$0.298/MMBtu. In this case, the releasing shipper has managed to reduce its transportation cost essentially to the maximum IT rate.

A more modest (and more likely) financial outcome for the releasing shipper occurs when the released capacity does not command the maximum FT rate. If instead it is resold at a 50-percent discount from the full reservation fee, the releasing shipper will earn $281 million, lowering its total capacity costs to $563 million, or $0.563/MMBtu. This corresponds to an effective reservation fee of $5.65/MMBtu (Table B4).

This example is still somewhat optimistic, even with the assumed discount on released capacity, since releasing shippers are unlikely to be able to resell all of their excess capacity during off-peak periods. Nevertheless, the example demonstrates that significant cost reductions may be available for shippers who are able to take advantage of the capacity release program.

Transition Costs

Transition costs will increase rates for Pipeline A for a few years (Table B5). This company is assumed to have $90 million of GSR costs to be recovered over 3 years, $18 million in stranded costs (for terminating contracts for upstream capacity) to be recovered over 3 years, and $10 million in new facility investments to be added to the rate base, which earns an 11 percent allowed rate of return (Table B1). (Since Account 191 costs are billed directly to the individual customers on whose behalf they were incurred, and do not affect overall rates, they are omitted from the example.)

GSR Costs	$90 million recovered over 3 years
Stranded Costs	$18 million recovered over 3 years
New Facilities	$10 million added to rate base

For each of the next 3 years, $30 million in GSR costs will be billed to customers—90 percent or $27 million to be recovered through a firm demand surcharge and the remaining $3 million through an increase in the maximum IT rate. Stranded costs of $6 million over each of the next 3 years will be recovered through a firm demand surcharge.

The firm demand surcharge is calculated by converting the $33 million in annual GSR and stranded costs allocated to firm customers to a monthly figure and dividing that by the peak capacity reservation:

$$\text{Firm Demand Surcharge} = \text{(Annual GSR and Stranded Costs Allocated to Firm Service)} / \text{12 months} / \text{Peak Firm Capacity} \tag{14}$$

$$= (\$27\text{ million} + \$6\text{ million}) / 12\text{ months} / 8.302\text{ TBtu}$$

$$= \$0.331/\text{MMBtu}$$

New facilities of $10 million will be added to the rate base. With a debt/equity ratio of 50/50 (Table B1), the debt and equity components of the new investment are each $5 million. The associated fixed costs include:

Return on Equity of 11 percent	$ 0.55 million
Interest on Debt of 9 percent	$ 0.45 million
Income Tax of 38 percent	$ 0.34 million
Annual Depreciation of 5 percent	$ 0.50 million
Ad Valorem Tax of 2 percent	$ 0.20 million
Total Increase in Fixed Costs	$ 2.04 million

Table B5. Transition Cost Recovery

GSR Costs		
TA	Total GSR Costs (million dollars)	$90
TB	GSR Recovery Period (years)	3
TC=TA/TB	Annualized GSR Cost (million dollars)	$30
TD=.9*TC	GSR Allocated to Firm Customers (million dollars)	$27
TE=.1*TC	GSR Allocated to Interruptible Customers (million dollars)	$3
Stranded Costs		
TF	Total Stranded Costs (million dollars)	$18
TG	Stranded Cost Recovery Period (years)	3
TH=TF/TG	Annualized Stranded Costs (million dollars)	6
New Investment		
TI	New Facilities Investment (million dollars)	$10
TJ=0.5*TI	Equity Financing (million dollars)	$5
TK=0.5*TI	Debt Financing (million dollars)	$5
Increase in Fixed Costs from New Investment (million dollars)		
TL=AI*TJ	Return on Equity	$0.55
TM=AJ*TK	Cost of Debt	$0.45
TN=AK*TL/(1-AK)	Income Tax	$0.34
TO=AL*TI	Depreciation	$0.50
TP=AM*TI	Ad Valorem Tax	$0.20
TQ=TL+TM+TN+TO+TP	Total Increase in Fixed Costs	$2.04
Rate Impacts		
TR=(TD+TH)/12/AP	Firm Demand Surcharge from GSR and Stranded Costs ($/MMBtu)	$0.331
TS=TQ/12/RA	Increase in Effective Monthly Reservation Fee from New Investment ($/MMBtu)	$0.019
TT=TE/AD	Increase in Effective Maximum IT Rate from GSR Cost ($/MMBtu)	$0.015
TU=TS*12/365	Increase in Maximum IT Rate from New Investment ($/MMBtu)	$0.001
TV=TT+TU	Total Increase in Maximum IT Rate ($/MMBtu)	$0.016

IT = Interruptible Transportation. GSR = Gas Supply Realignment Cost.
Note: Row names begin with T to designate the "Transition Cost" table.
Source: Energy Information Administration, Office of Oil and Gas: based on information provided by Federal Energy Regulatory Commission, Office of Pipeline Regulation.

The increase in fixed costs resulting from the new investment is allocated to firm and interruptible rates using the same procedure used in determining SFV rates. Specifically:

Increase in Monthly Reservation Fee	=	Increase in Fixed Costs / 12 months / Reservation Fee Billing Units	(15)
	=	$2.04 million / 12 months / 8.85 TBtu	
	=	$ 0.019/MMBtu	

Increase in Maximum IT Rate	=	Increase in Annual Reservation Fee / 365 days	(16)
	=	$0.019/MMBtu * 12 months / 365	
	=	$0.001/MMBtu	

Finally, the maximum IT rate is adjusted further to incorporate the $3 million in annual GSR costs allocated to interruptible service:

Further Increase in Maximum IT Rate	=	Annual GSR Costs Allocated to Interruptible Service / Projected Interruptible Throughput	(17)
	=	$3 million / 200 TBtu	
	=	$0.015/MMBtu	

The total increase in the maximum IT rate from transition costs is therefore $0.016/MMBtu.

The total impact on FT rates consists of an increase in the basic reservation fee of $0.019/MMBtu resulting from the new investment and a demand surcharge of $0.331/MMBtu to recover GSR and stranded costs.

Summary

Implementation of Order 636 has changed the way transportation rates are calculated. The numerical examples presented in this appendix show how each component of these rates is derived. Unlike in Table 6, Chapter 2, however, the examples do not demonstrate the net impact of all these changes on the bottom line reservation fee paid by a firm customer. The cumulative impacts of these changes on the reservation fee are presented below.

To derive the effective monthly reservation fee after interruptible revenue crediting, $8.25 per MMBtu reported in Table 6, it is necessary to add the increase in the reservation fee associated with new investment (TS in Table B5), or $0.02 per MMBtu, to the reservation fee calculated after crediting, or $8.23 per MMBtu (IN in Table B3).

The bottom line effective monthly reservation fee after releasing capacity, $5.44 per MMBtu reported in Table 6, includes the $0.02 per MMBtu associated with transition costs (Table 6), plus the effective monthly reservation fee after releasing capacity of $5.65 per MMBtu (CR in Table B4), minus the $0.23 per MMBtu (Table 6) reduction in costs associated with releasing capacity. The effective monthly reservation fee after capacity has been released calculated in Table B4 does not take into account the effects of transition costs or interruptible revenue crediting.

Appendix C

Financial Analysis Methodology

Appendix C

Financial Analysis Methodology

This appendix presents the methodology used to estimate the measures of financial performance presented in Chapter 5. The measures were calculated for each industry segment (producers, interstate pipeline companies, and local distribution companies), based on a sample of companies contained within the Standard and Poor's (S&P) Compustat database. Both annual and quarterly data items from the database have been used in this analysis. For the calculation of financial ratios used in the chapter, annual data were used from 1985 to 1993. Average stock prices were calculated based on monthly stock prices available from January 1985 through March 1994. Aggregation of variables and calculations of financial measures follow the procedures suggested by Standard and Poor's.

Segment Sample of Companies

The analysis was conducted for the major segments of the natural gas industry based on availability of data within the Compustat database from 1985 to 1993. The companies that comprise the sample for each of the segments analyzed are listed in Table C1, along with corresponding stock ticker symbols, S&P industry code numbers, and S&P company codes.

The producer segment of the industry was divided between major and independent producers. The major producer sample represents 96 percent of the 1992 U.S. dry gas production of those companies classified as such by the Financial Reporting System (FRS) of the Energy Information Administration 's Office of Energy Markets and End Use. The independent producer sample represents 67 percent of the 1992 dry gas production in the United States by publicly traded independent producers.

The interstate pipeline company segment was examined both with and without Columbia Gas System in the sample. This company was so isolated because it filed for Chapter 11 bankruptcy protection. The companies included in the sample represent parent companies of all interstate pipeline companies available on the Compustat database.

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

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

Calculation of Financial Performance Measures

The items selected from the Compustat database, along with the corresponding annual and quarterly S&P item number, for use in the calculation of the measures of financial performance for each segment sample of the U.S. natural gas industry are found in Table C2. The calculations for these measures are presented below. Note that the summations in each calculation refer to the aggregation of companies within each segment.

Adjusted Average Stock Price

In the Compustat quarterly database, stock price data are available for each month of the quarter. The monthly adjusted average stock price (presented in Figure 31) is calculated using quarterly high and low stock price variables for each month of the quarter (quarterly items 63-68), the quarterly common shares outstanding (quarterly item 61), and the quarterly adjustment factor (quarterly item 17). The adjustment factor is a ratio that adjusts per-share data, such as stock prices for all stock splits and stock dividends that occur subsequent to the end of a given year. In the financial performance boxes for each segment, the average adjusted stock price presented is for December of each year. For each segment, from January 1985 to March 1994, the following calculation was used for each month:

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

where,

AASP	=	Adjusted Average Monthly Stock Price
P_h	=	Company Stock Monthly Price-High

P_l	=	Company Stock Monthly Price-Low
CSO	=	Quarterly Common Shares Outstanding
ADJ	=	Company Quarterly Adjustment Factor

In the first quarter of 1994, the items CSO and ADJ were unavailable. As a proxy, the fourth quarter, 1993 CSO and ADJ were used instead. Additionally, in the fourth quarter, 1993 CSO and ADJ were unavailable for a limited number of companies. In these cases, the third quarter, 1993 CSO and ADJ were used as proxies.

Average Bond Rating

For each year, a weighted average S&P bond rating was calculated for each segment based on net sales. Some companies in the sample, however, did not have consistent time series data for bond ratings. For this reason, a subset of companies, as noted by the asterisks in Table C1, was used for each segment in the following calculation:

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

where,

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

Long-Term Debt as a Percent of Invested Capital

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

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

where,

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

Times Interest Earned Ratio

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

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

where,

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

Return on Common Equity

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

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

where,

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

Price/Earnings Ratio

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

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

where,

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

NI = Net Income (annual item 172)

Market/Book Value Ratio

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

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

where,

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

Table C1. Natural Gas Industry Segment Sample Companies

	Company Stock Ticker Symbol	S&P Industry Code	S&P Company Code	
Producers (Majors)				
Amerada Hess Corp.	AHC	2911	23551	
Amoco Corp.	AN	2911	31905	*
Atlantic Richfield Co.	ARC	2911	48825	*
British Petroleum Plc -ADR	BP	2911	110889	*
Broken Hill Proprietary - ADR	BHP	1311	112169	
Burlington Resources Inc.	BR	1311	122014	
Chevron Corp.	CHV	2911	166751	*
Enron Oil & Gas	EOG	1311	293562	
Exxon Corp.	XON	2911	302290	*
Mobil Corp.	MOB	2911	607059	*
Occidental Petroleum Corp.	OXY	1311	674599	*
Oryx Energy Co.	ORX	1311	68763F	
Phillips Petroleum Co.	P	2911	718507	*
Royal Dutch/Shell Group Comb.	RDSC.CM	2911	78025C	
Soc Natl Elf Aquitn - ADR	ELF	2911	833658	
Texaco Inc.	TX	2911	881694	*
Unocal Corp.	UCL	2911	915289	*
USX Corp.- Consolidated	MROX.CM	2911	90399Y	
Producers (Independents)				
Alamco Inc.	AXO	1311	10742	
Anadarko Petroleum Corp.	APC	1311	32511	*
Apache Corp.	APA	1311	37411	
Basin Expl. Inc.	BSNX	1311	70107	
Brown (Tom), Inc.	TMBR	1311	115660	
Cabot Oil & Gas Corp - CLA	COG	1311	127097	
Chieftain International Inc.	CID	1311	16867C	
CODA Energy	CODA	1311	191886	
Crystal Oil Company	COR	1311	229385	
DEKALB Energy Company	ENRGB	1311	244874	
Dorchester Hugoton - LP	DHULZ	1311	258205	
Forest Oil Corp.	FOIL	1311	346091	*
Hadson Energy Resources Corp.	HDX	1311	405019	
Hallwood Cons. Res. Corp.	HCRC	1311	40636V	
Hallwood Energy Prtnr. - LP	HEP	1311	40636P	
Kelley Oil & Gas Ptrs. - LP	KLY	1311	487736	
Louisiana Land & Exploration	LLX	2911	546268	*
Maxus Energy Corp.	MXS	1311	577730	*
Mesa Inc.	MXP	1311	590911	
Noble Affiliates Inc.	NBL	1311	654894	*
Norcen Energy Res.	NCN	1311	655492	
Nuevo Energy Co.	NEV	1311	670509	
Parker & Parsley Petroleum	PDP	1311	701018	
Plains Petroleum Company	PLP	1311	726529	
Pogo Producing Co.	PPP	1311	730448	*
Presidio Oil - CLA	PRS.A	1311	741016	
Sage Energy Co.	6041C	1311	786629	
Samson Energy Co. LP	SAM	1311	796022	
Sante Fe Energy Resources	SFR	1311	802012	*
Snyder Oil Corp.	SNY	1311	833482	
St. Mary Land & Explor. Co.	MARY	1311	792228	
Tide West Oil Company	TIDE	1311	886355	
Wainoco Oil Corp.	WOL	2911	930676	*
Wolverine Exploration Company	WEXC	1311	977892	
Interstate Pipeline Companies				
Arkla Inc.	ALG	4923	41237	*
Coastal Corp.	CGP	4922	190441	*
Columbia Gas System	CG	4923	197648	*
Consolidated Natural Gas Co.	CNG	4923	209615	*
El Paso Natural Gas Co.	EPG	4922	283695	*
	Company Stock Ticker Symbol	S&P Industry Code	S&P Company Code	
Enron Corp.	ENE	4923	293561	*
KN Energy Inc.	KNE	4923	482620	*
Panhandle Eastern Corp.	PEL	4922	698462	*

Questar Corp.	STR	4923	748356
Sonat Inc.	SNT	4922	835415 *
Transco Energy Co.	E	4922	893532 *
Williams Cos Inc.	WMB	4922	969457 *

Local Distribution Companies (Gas Only)

Allegheny & Western Energy	ALGH	4924	17227
Atlanta Gas Light Co.	ATG	4924	47753
Atmos Energy Corp	ATO	4924	49560
Bay State Gas	BGC	4924	72612 *
Berkshire Gas Co.	BGAS	4924	84653
Brooklyn Union Gas Co.	BU	4924	114259
Cascade Natural Gas Corp.	CGC	4924	147339 *
Chesapeake Utilities Corp.	CPK	4923	165303
Colonial Gas Co.	CGES	4924	195674
Connecticut Energy Corp.	CNE	4924	207567
Connecticut Natural Gas Corp.	CTG	4924	207651 *
Corning Natural Gas Corp.	3CNNG	4923	219381
Delta Natural Gas Co. Inc.	DGAS	4923	247748
Eastern Enterprises	EFU	4924	27637F
Energen Corp.	EGN	4924	29265N
EnergyNorth Inc.	ENNI	4924	292925
Enserch Corp.	ENS	4923	293567
Equitable Resources Inc.	EQT	4923	294549 *
Essex County Gas Co.	ECGC	4924	296772
Fall River Gas Co.	3FALL	4924	306279
Great Falls Gas Company	GFGC	4924	390406
Indiana Energy Inc.	IEI	4924	454707
Laclede Gas Co.	LG	4924	505588
MCN Corp.	MCN	4924	55267J
Mobile Gas Service Corp.	MBLE	4924	607369
National Fuel Gas Co.	NFG	4924	636180
National Gas & Oil Co.	NLG	4923	636195
New Jersey Resources	NJR	4924	646025
NICOR Inc.	GAS	4924	654086 *
North Carolina Natural Gas	NCG	4923	658221
Northwest Natural Gas Co.	NWNG	4924	667655 *
NUI Corp.	NUI	4924	629430
Oneok Inc.	OKE	4923	682678
Pacific Enterprises	PET	4924	694232
Pennslvania Enterprises Inc.	PENT	4932	708720
Peoples Energy Corp.	PGL	4924	711030
Piedmont Natural Gas Co.	PNY	4924	720186
Providence Energy Corp.	PVY	4924	743743
Public Service Co. of N.C.	PSNC	4924	744516
Roanoke Gas Co.	3RGCO	4924	769858
South Jersey Industries	SJI	4924	838518
Southeastern Michigan Gas Entrpr.	SMGS	4924	841825
Southern Union Co.-New	SUG	4924	844030 *
Southwest Gas Corp.	SWX	4923	844895 *
Southwestern Energy Co.	SWN	4923	845467
United Cities Gas Co.	UCIT	4924	909823
Valley Resources Inc.	VR	4924	920062
Washington Energy Co.	WEG	4924	938815
Washington Gas Light Co.	WGL	4924	938837 *
WICOR Inc.	WIC	4924	929253
Wisconsin Southern Gas Co.	WISC	4924	977045
Yankee Energy Sys Inc.	YES	4924	984779

	Company Stock Ticker Symbol	S&P Industry Code	S&P Company Code
Local Distribution Companies (Combination Gas and Electric)			
Baltimore Gas & Electric	BGE	4931	59165 *
Central Hudson Gas & ELectric	CNH	4931	153609 *
Cilcorp Inc.	CER	4931	171794
Cincinnati Gas & Electric	CIN	4931	172070 *
CIPSCO Inc.	CIP	4931	125539
Citizens Utilities	CZN.A	4931	177342 *
CMS Energy Corp.	CMS	4931	125896
Commonwealth Energy System	CES	4931	202800
Consolidated Edison of NY	ED	4931	209111 *
Consumers Power Co.	CMS1	4931	210615
Delmarva Power & Light	DEW	4931	247109 *
DPL Inc.	DPL	4931	233293
Florida Public Utilities Co.	FPU	4931	341135
IES Industries Inc.	IES	4931	44949M
Illinois Power Co.	IPC	4931	452092 *
Interstate Power Co.	IPW	4931	461074 *
Iowa-Illinois Gas & Electric	IWG	4931	462470 *
LG&E Energy Corp.	LGE	4931	501917
Long Island Lighting	LIL	4931	542671 *
Madison Gas & Electric Co.	MDSN	4931	557497
MDU Resources Group Inc.	MDU	4932	552690 *
Midwest Resources	MWR	4931	598374
Minnesota Power & Light	MPL	4931	604110 *
Montana Power Co.	MTP	4931	612085 *
New York State Electric & Gas	NGE	4931	649840 *
Niagara Mohawk Power	NMK	4931	653522 *
NIPSCO Industries Inc.	NI	4931	629140
Northern States Power-MN	NSP	4931	665772 *
Northwestern Public Service Co.	NPS	4931	668231 *
Orange & Rockland Utilities	ORU	4931	684065 *
Pacific Gas & Electric	PCG	4931	694308 *
Pacificorp	PPW	4931	695114 *
Public Service Co. of Colorado	PSR	4931	744448 *
Public Service Co. of N. Mexico	PNM	4931	744499 *
Public Service Entrp.	PEG	4931	744573
Rochester Gas & Electric	RGS	4931	771367 *
San Diego Gas & Electric	SDO	4931	797440 *
Scana Corp.	SCG	4931	805898 *
Sierra Pacific Res.	SRP	4931	826425
Southern Indiana Gas & Elec	SIG	4931	843163 *
St. Joseph Light & Power	SAJ	4931	790654 *
UGI Corp.	UGI	4932	902681
Unitil Corp.	UTL	4931	913259
Utilicorp United Inc.	UCU	4931	918005
Washington Water Power	WWP	4931	940688 *
Western Resources Inc.	WR	4931	959425 *
Wisconsin Energy Corp.	WEC	4931	976657
Wisconsin Public Service	WPS	4931	976843 *
WPL Holdings Inc.	WPH	4931	929305

*Denotes companies with consistent time series bond rating information used in segment bond rating calculations.
Source: Standard and Poor's Compustat Services, Inc. "Compustat" database.

Table C2. Compustat Variables Used in Analysis

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

Source: Standard and Poor's Compustat Services, Inc. "Compustat" database.