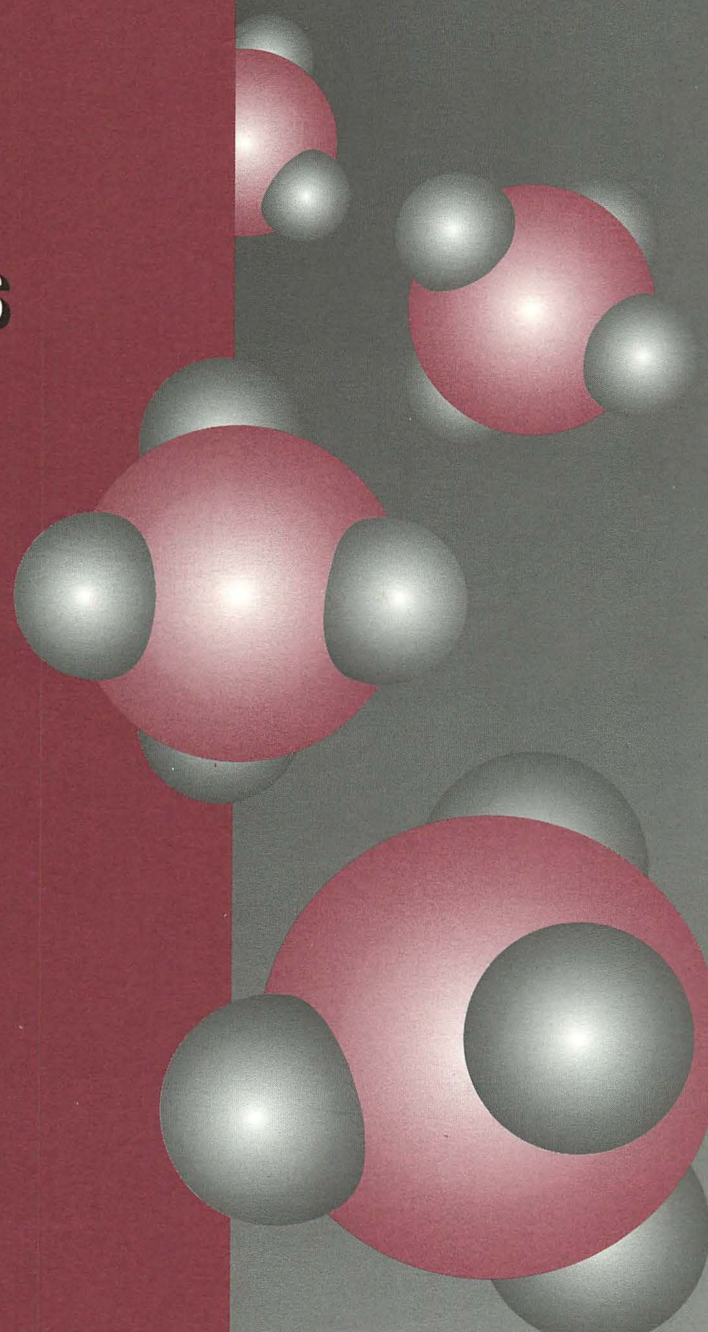
The Potential for Natural Gas in the United States

Transmission and Storage

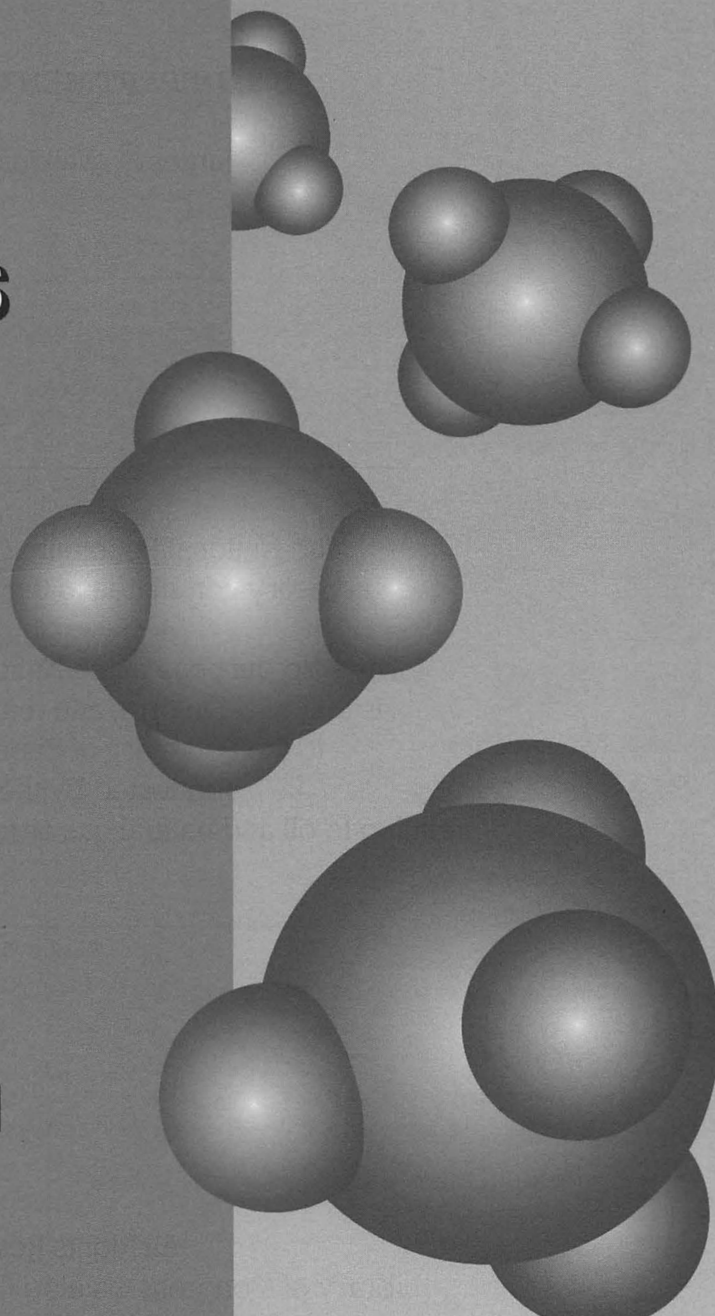


December 1992
National Petroleum Council

On the Cover: Graphic Representation of Methane Molecules, CH_4, the Primary Chemical Compound in Natural Gas.

The Potential for Natural Gas in the United States

Transmission and Storage



December 1992
National Petroleum Council

Committee on Natural Gas
Frank H. Richardson, Chairman

The National Petroleum Council is a federal
advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council
is to advise, inform, and make recommendations
to the Secretary of Energy on any matter
requested by the Secretary
relating to oil and natural gas or to the oil and gas industries.

Library of Congress Catalog Card Number: 92-82047

Printed in the United States of America

NATIONAL PETROLEUM COUNCIL

1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100

December 17, 1992

The Honorable
James D. Watkins
Secretary of Energy
Washington, D.C. 20585

Dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith the Council's report entitled *The Potential for Natural Gas in the United States*. This report was prepared in response to your request and was unanimously approved by the membership at their meeting today.

Natural gas has the potential to make a significantly larger contribution both to this nation's energy supply and its environmental goals. Achieving that potential will take a commitment of innovation, leadership, and resources by the industry to overcome challenges that arise from its current operations, its history, and its regulation. The National Petroleum Council concludes that industry has already initiated actions in support of that commitment and believes the industry is prepared to continue those activities.

This study finds that natural gas is uniquely positioned to take on this expanded role for three reasons:

1. Natural gas can be produced and delivered in volumes sufficient to meet expanding market needs at competitive prices.
2. Natural gas is a clean-burning fuel, and can be used in a variety of applications to satisfy environmental requirements.
3. Natural gas is a secure, primarily domestic source of energy that can help improve the national balance of foreign trade.

In addition, much of the groundwork necessary to develop a more competitive and customer-oriented industry has already been laid.

Perceptions of natural gas that arise from its heavily regulated past represent the greatest challenge to be overcome by the industry. In particular, the industry must pay more attention to meeting customer needs through greater efficiency and more competitive services. Efforts like this study to define the problem and outline its solution, have become critical to realization of natural gas' potential.

The National Petroleum Council sincerely hopes the enclosed report will be of value to the Department of Energy, and government at all levels, as natural gas and the natural gas industry realize their potential.

Respectfully submitted,

Ray L. Hunt

Ray L. Hunt
Chairman

Enclosure

TABLE OF CONTENTS

APPENDICES

SUMMARY

OVERVIEW

The U.S. interstate natural gas transmission industry is currently in the midst of the most significant business restructuring of its history. Historically, this has been a highly regulated business with the goal of obtaining supplies of natural gas and providing those supplies on demand primarily to local distribution companies, which extended the service to residential, commercial, industrial, and electric generation end users. Over the last few years, interstate natural gas transmission companies have been increasingly changing their roles as buyers and sellers of natural gas to that of open-access transporters of natural gas. The final steps toward open access, market-driven competition, and light-handed regulation are now on the horizon. It is within this transitional environment that the findings and recommendations of this portion of the National Petroleum Council (NPC) study are offered in order to realize the potential of the transmission and storage system, as described below:

The natural gas transmission and storage system provides economic, efficient, and reliable natural gas services in response to customer needs, enabling natural gas to make a larger contribution to our nation's energy needs and environmental goals.

The natural gas transmission and storage system is the critical link between supply and demand. Therefore, this study of the potential for natural gas to make a larger contribution to the nation's energy needs and environmental goals included the following objectives for the analysis of the transmission and storage system:

Provide analysis on the capability of the U.S. transmission and storage system to assist in expanding the use of natural gas in the United States and to integrate this analysis into the overall NPC study.

Review of this analysis provided the following key findings:

- The existing U.S. transmission and storage system is a valuable asset that plays an integral role in the U.S. energy industry.
- The existing system can support a growing U.S. natural gas market.
- There will be a need for construction of new facilities to adapt to changing supply and market patterns; the estimated cost of this construction is in line with past experience and should not be a major constraint to future industry growth.
- The natural gas transmission and storage system has—and continues to improve—the ability to provide economic, efficient, and reliable service responsive to customer needs.

- The natural gas transmission and storage system needs to further improve its ability to provide economic, efficient, and reliable service responsive to customer needs.

In light of these findings, the National Petroleum Council developed the overall recommendation that **participants involved in the natural gas industry take specific actions to improve the transmission and storage system's ability to provide economic, efficient, and reliable natural gas service responsive to customer needs.** The five parts to this overall recommendation are:

- Industry and regulators should support efforts to provide new, innovative market-responsive services and rate structures to respond to customer needs.
- The industry must improve its ability to construct new facilities, as required, on a timely basis.
- The industry should expand its efforts with customers to identify and address specific reliability concerns.
- Industry and regulators should support efforts to increase customer choices by increasing access to capacity at both the state and federal levels.
- Industry and regulators should make it easier for customers to buy and transport gas by supporting efforts to develop guidelines for operating procedures.

FINDINGS

The Existing U.S. Natural Gas Transmission and Storage System Is a Valuable Asset That Plays an Integral Role in the U.S. Energy Industry.

From 1930 to 1972, natural gas consumption in the United States grew at an annual rate of 6 percent, peaking at 22.1 trillion cubic feet (TCF) in 1972. After declining to 16.2 TCF in 1986, consumption has steadily recovered and has increased to 19.2 TCF in 1991 (Figure 1). In contrast to natural gas consumption before 1986, the transmission and storage system continued to expand and today there are about 280,000 miles of gas transmission pipeline and approximately 8 TCF of storage capacity (Figures 2 and 3). The cumulative investment in

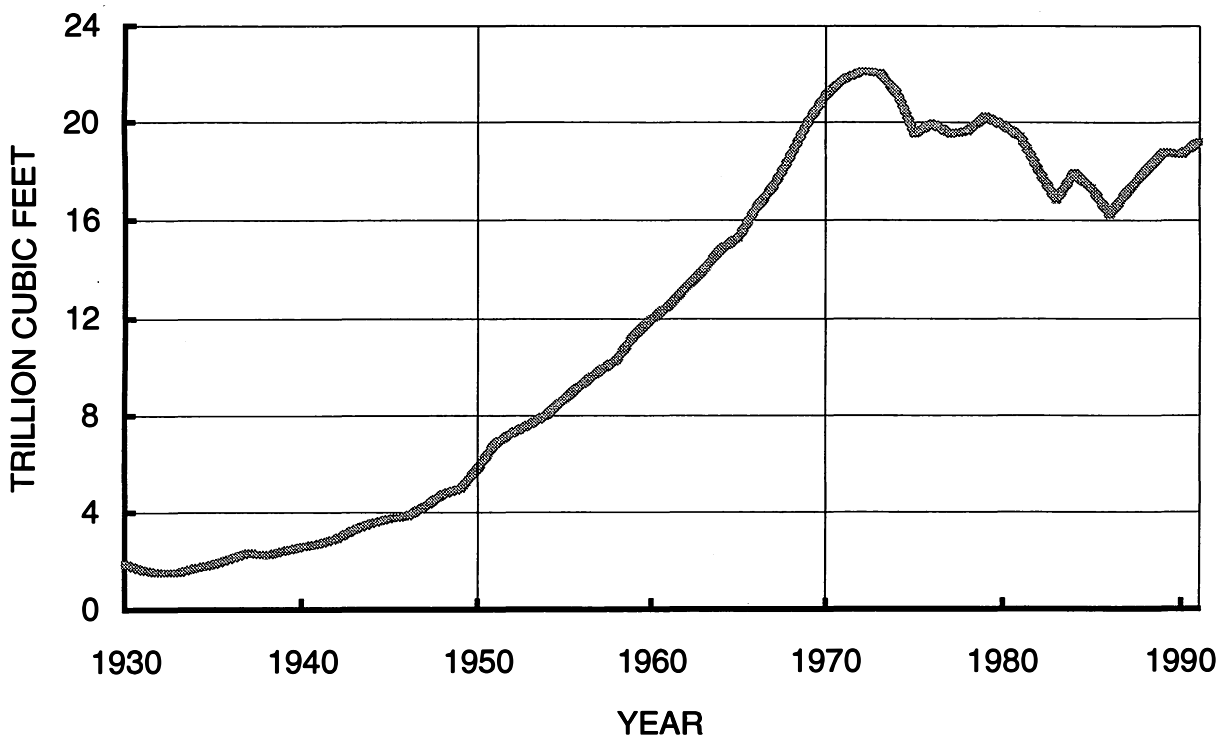
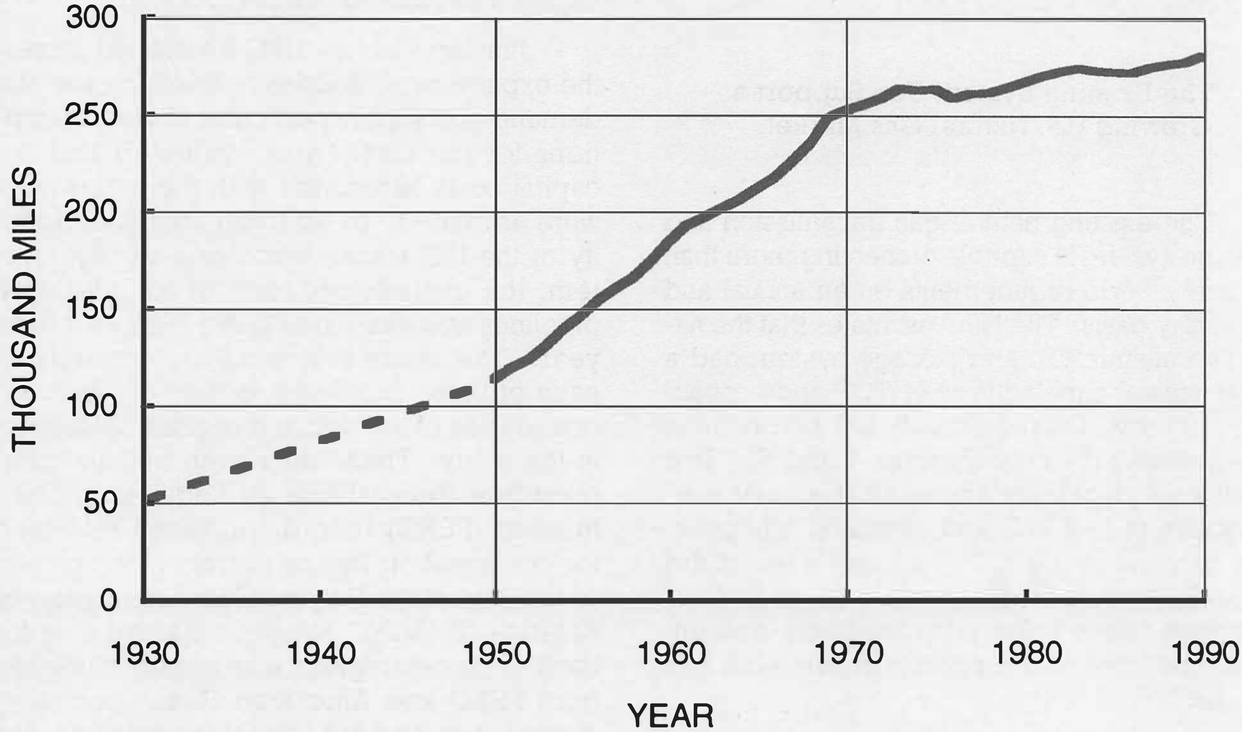
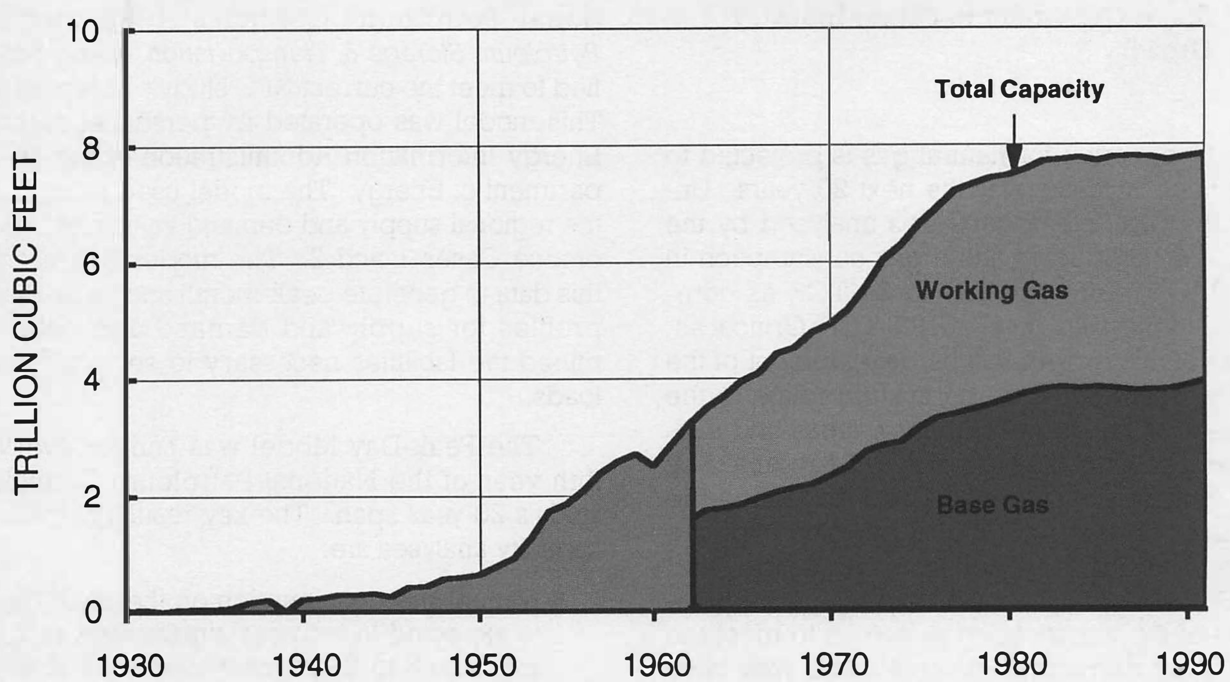


Figure 1. Total Natural Gas Consumption—1930-1991.



NOTE: Data prior to 1950 less reliable.

Figure 2. Miles of Natural Gas Transmission Line.



NOTE: Prior to 1962, storage data not distinguished between Base Gas and Working Gas.

Figure 3. Underground Natural Gas Storage Capacity—1930-1991.

major interstate pipeline systems exceeds $50 billion as of the end of 1991.

The Existing System Can Support a Growing U.S. Natural Gas Market.

The existing natural gas transmission and storage system is capable of meeting more than its current firm requirements on an annual and peak-day basis. The NPC estimates that the nation's transmission and storage system had a 1991 annual capability of 24 TCF and a peak-day capacity of approximately 120 billion cubic feet per day (BCF/D) (Figures 4 and 5). This additional capability above 1991 annual consumption of 19.2 TCF and estimated firm peak-day demand of 102 BCF/D allows for use of this capacity by non-firm customers on peak days, provides redundancy, adds reliability, and enables the system to support a growing U.S. gas market.

There Will Be a Need for Construction of New Facilities to Adapt to Changing Supply and Market Patterns; the Estimated Cost of This Construction Is in Line with Past Experience and Should Not Be a Major Constraint to Future Industry Growth.

The market for natural gas is projected to grow substantially over the next 20 years. Under the two Reference Cases analyzed by the NPC for this study, natural gas consumption in 2010 will range from 21 to 24 TCF, as compared to the 1991 level of 19.2 TCF. Critical aspects of this growth for the development of the transmission and storage system relate to the location of the growing market areas and supply sources and the type of service required by the consumers. These factors influence the balance between additional pipeline capacity, development of underground storage, and peak-shaving facilities. The principal requirement of the transmission system is to meet the peak-day demand of its customers who have contracts for firm service. To meet this requirement, the industry developed facilities that are a combination of transmission lines to bring the gas to the market areas and of storage closer to market areas to meet surges in demand.

Utilizing the two NPC Reference Cases, the expansion of facilities needed to meet the demand and supply particular to the assumptions for the Cases was evaluated and the capital costs associated with the expansions were estimated. To establish the base capacity of the U.S. transmission and storage system, the current capacity of 37 interstate pipelines was examined using 1989 as a base year. The study reviewed the capacity of each of these pipelines as they crossed the boundaries of ten demand regions as defined in the study. These data were initially compiled from Federal Energy Regulatory Commission (FERC) records and then reviewed for confirmation by the member companies of the Interstate Natural Gas Association of America (INGAA). Similarly, storage data for each of the ten regions was initially compiled from FERC and American Gas Association storage data and subsequently reviewed and confirmed by INGAA member companies and other storage operators.

Computer models were utilized to analyze the system's ability to move natural gas supplies to market. To assess the requirements for future facilities, a model included in the National Petroleum Council's 1989 study, *Petroleum Storage & Transportation*, was modified to meet the current NPC study's objectives. This model was operated by personnel of the Energy Information Administration of the Department of Energy. The model used as inputs the regional supply and demand values for Reference Cases 1 and 2. The model then used this data to generate peak-month and peak-day profiles for supply and demand and determined the facilities necessary to service firm loads.

The Peak-Day Model was run for every fifth year of the National Petroleum Council study's 20-year span. The key results of these capacity analyses are:

- Natural gas consumption on the peak day is expected to increase significantly, ranging from 8 to 23 percent over 1991 levels by 2010 due to an increase in firm load requirements, including growth in the electric generation markets.

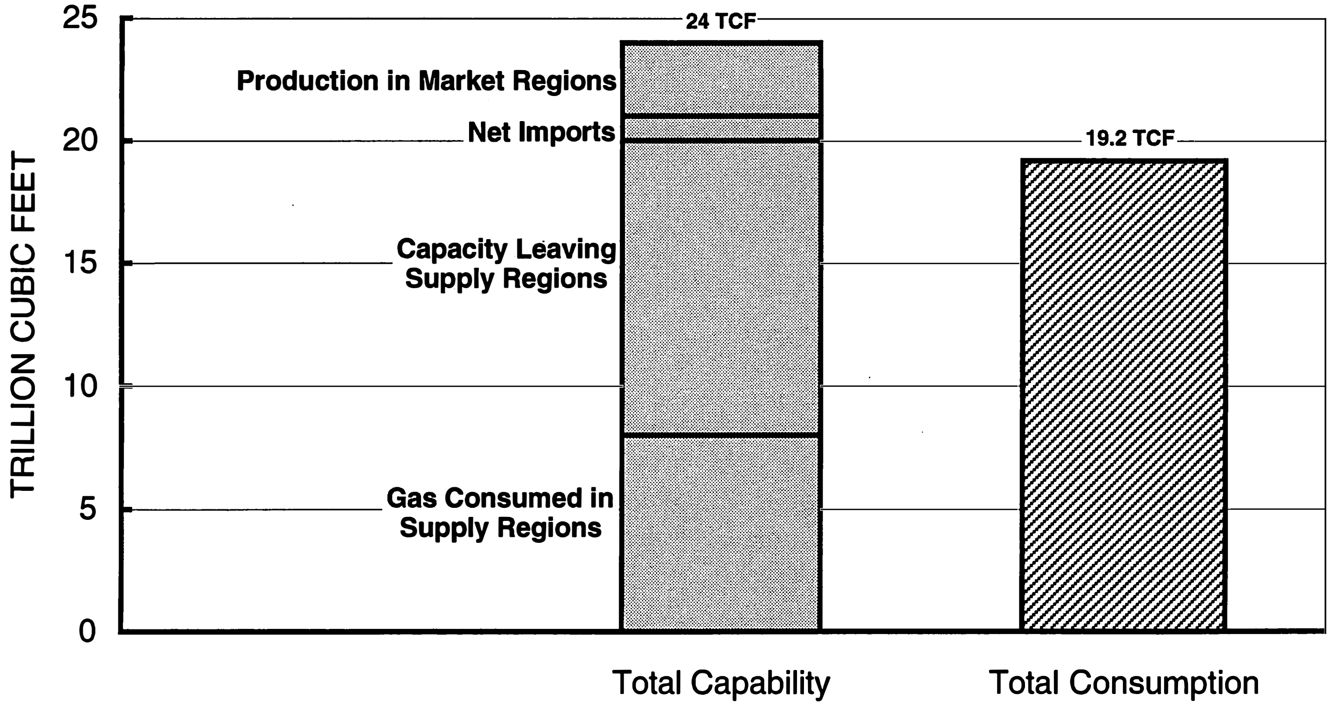


Figure 4. 1991 U.S. Transmission and Storage System—Annual Capability.

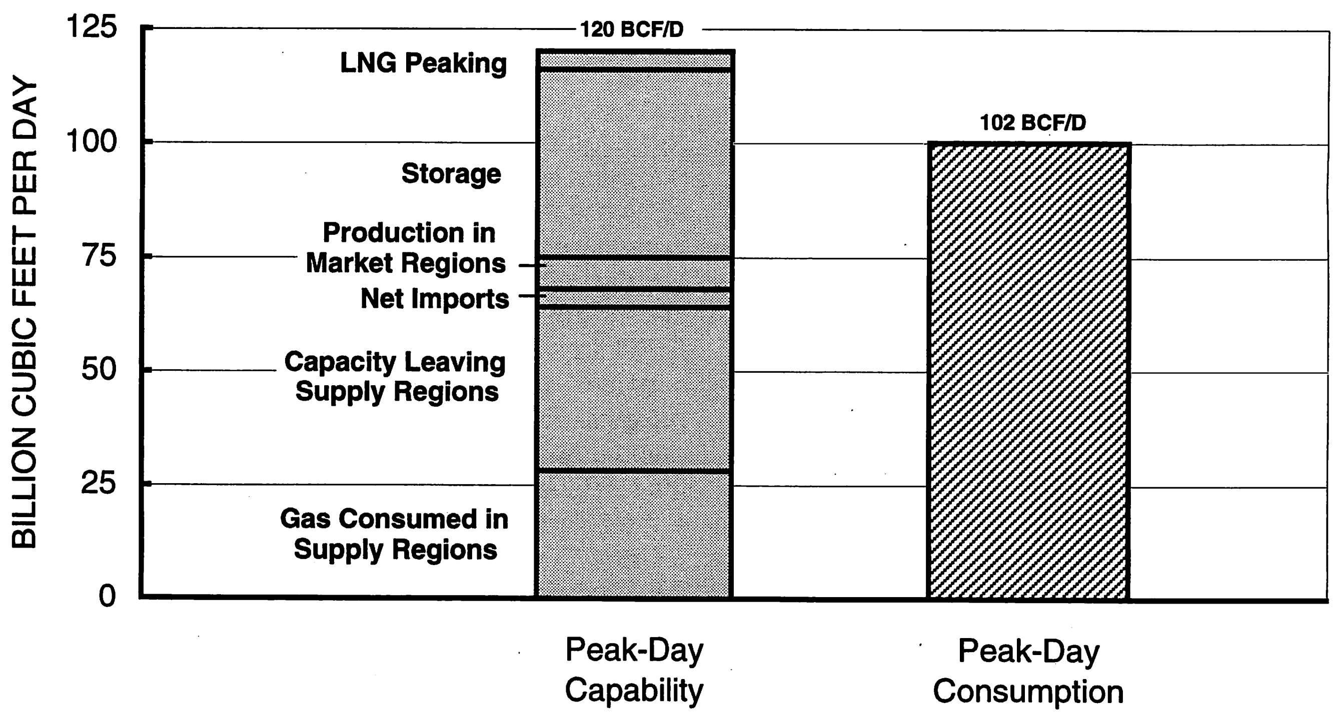


Figure 5. 1991 U.S. Transmission and Storage System—Peak-Day Capability.

- A significant shift in regional supply and consumption patterns will affect future transmission and load balancing requirements by 2010 due to a decline in production from the Southwest Central region and the increasing supplies from new supply sources (such as the North Central region and Canada).
- Additional transmission and storage capability will be required in the post-2000 period to move gas from the North Central region and from Canada to neighboring regions and to move gas into the Northeast and Pacific regions.

To estimate the required future capital investment in the two NPC Reference Cases, unit costs for expansions were established by studying FERC and Canadian National Energy Board certificate filings. Unit costs were established for incremental pipeline systems and existing pipeline expansions, and construction of storage and peak-shaving facilities. Below are the estimated U.S. capital expenditure requirements in 1991$ through 2010 for the two Cases:

Reference Case 1	$16 billion
Reference Case 2	$6 billion

Based on Reference Case 1, the above capital investments result in an estimated U.S. capability to transport natural gas as follows:

	Peak Day (BCF/D)	
	Capability	Firm Requirements
1995	126	114
2000	129	118
2005	131	122
2010	137	126
	Annual (TCF/Year)	
	Capability	**Total Demand**
1995	26	21
2000	27	22
2005	28	24
2010	30	24

As previously stated for the existing system, the projected additional peak-day and annual capability would allow use of this capability by non-firm customers on peak days, provide redundancy, and add reliability.

The capital expenditures would range between approximately $0.3 and $0.9 billion per year if expended evenly over the 1992-2010 period. A survey of pipeline companies was also conducted to estimate future maintenance and replacement expenditures. This survey resulted in an estimate of approximately $1.7 billion per year. Therefore, the total annual average industry expenditure is estimated to be $2.0-2.6 billion per year. These expenditures are within the average total industry expenditures from 1970 to 1990 of $2.4 billion per year (1991$) and should not be a major constraint to future industry growth.

The Natural Gas Transmission and Storage System Has—and Continues to Improve—the Ability to Provide Economic, Efficient, and Reliable Service Responsive to Customer Needs.

The nation's transmission and storage system is constantly being upgraded and expanded to meet changing supply and demand requirements. Recent projects have been placed in service and others are proposed that allow greater access to supply areas and support increasing natural gas consumption. In addition, there are a number of projects recently approved by the FERC, or pending FERC approval, which provide significant new capacity. If approved and constructed, these projects would provide nearly 6.8 BCF/D in additional capacity to serve growing markets in the Northeast, New York, New Jersey, the Western U.S., and the Southeastern U.S. Also, about 1.4 BCF/D will be used to export gas to Mexico. The New York/New Jersey region will also see a significant increase in capacity, principally from Canada. There are also a number of storage projects being planned. Altogether, these projects would add an additional 99 BCF in winter season supplies and over 2.6 BCF/D in peak-day deliverability.

Operation of today's pipeline system has been significantly modernized over the last few years through utilization of remote terminal units, microwave communication, and computerized control systems. The industry primarily conducts its research and development (R&D) through the Gas Research Institute (GRI), the American Gas Association, and manufacturers. While selected gas industry research and development projects target cost reductions in new construction, most of the gas transmission industry's effort is directed at the following objectives:

- Reducing transportation costs
- Assuring deliverability of natural gas to customers
- Enhancing transport system reliability
- Maintaining the integrity of the gas transport system
- Reducing compressor station emissions and minimizing the cost of compliance
- Operating and maintaining the gas transport system, and constructing new facilities in a safe and environmentally desirable manner.

Specific R&D thrusts are in the areas of pipeline prime mover emissions reduction and compressor station efficiency improvement, automation systems, transport measurement technology, transmission piping systems, sensors and controls, and storage technology. This includes basic research in areas such as fundamental pipeline materials, gas flow fluid mechanics, and combustion chemistry. The gas transmission industry has also, through GRI, begun operation of a metering research facility, and a non-destructive evaluation research facility is under construction.

Pipelines are typically located in underground right-of-ways, inherently posing minimal threat to the environment. Heightened awareness and growing sophistication on the part of pipeline companies and federal, state, and local regulatory officials, as well as improved construction practices and technology, have minimized the potential for, and the incidence of, environmental harm. In addition, the Clean Air Act Amendment of 1990 has tight restrictions on the emissions of critical pollutants and "greenhouse" related gases, which will significantly affect the expansion and operation of natural gas transmission systems, particularly at compressor stations.

Perhaps the most publicized and most evolutionary improvement in the natural gas transmission system's ability to provide economic, efficient, and reliable service responsive to customer needs is the system's continued transition toward a more open and competitive environment. Beginning in 1978, with the Natural Gas Policy Act, which began a program of phased deregulation of natural gas wellhead sales, the natural gas industry has been undergoing a fundamental shift in regulation and structure toward a reliance on competitive markets. In 1985, the FERC issued Order 436, a voluntary open-access transportation program. Pipelines participating in the program were authorized to provide transportation services on a non-discriminatory basis, with significantly fewer regulatory restrictions than in the past. Local distribution companies were allowed to reduce purchases of natural gas from the pipeline and to arrange for direct purchases from alternate suppliers. By 1992, over 90 pipelines were participating in the open-access program, and nearly 80 percent of all natural gas moved in interstate commerce is shipper-owned (with the remaining 20 percent being traditional pipeline sales volumes).

In response to concerns that open-access transportation under Order 436 was not comparable in quality to interstate pipeline natural gas sales services, the FERC issued Order 636 on April 8, 1992. FERC Order 636 mandates the almost complete unbundling of pipeline gas sales from transportation services by the 1993-94 winter heating season. Pipeline companies are required to restructure their contractual relationships with existing firm sales customers and to offer firm no-notice transportation service in place of firm citygate sales. This order, which applies to interstate pipelines, requires pipelines to offer storage, gathering, transportation, and sales on a separate unbundled basis and removes regulatory price controls from the pipelines' sales of natural gas. The order includes a capacity release program intended to foster a secondary market for pipeline capacity. Order 636 does not deregulate natural gas services or rates, but instead uses a light-handed regulatory approach that relies more on competition, arms-length negotiated contracts, and prohibitions of undue discrimination.

The Natural Gas Transmission and Storage System Needs to Further Improve Its Ability to Provide Economic, Efficient, and Reliable Service Responsive to Customer Needs.

The need to improve natural gas service stems from concerns expressed by focus group participants and participants in this NPC study. Focus group discussions were conducted as part of this study with key groups that comprise the industry, including regulators, customers, and suppliers. Some of the concerns and perceptions expressed by the focus group participants were:

- Service reliability as a result of historical interruptions and curtailments
- Financial health of the interstate pipeline industry limiting its ability to finance new facilities
- Changing and complex procedures for obtaining pipeline services
- Uncertain and changing federal or state regulation
- Industry inefficiencies due to fragmentation and cost-based regulation
- Industry and regulators show little interest or respect for the needs of customers.

Participants in the NPC study have cited several additional concerns of the transmission and storage system in achieving its potential, including:

- Ineffective communication of service quality and service expectations
- Lack of incentives to provide new services, maximize efficiency, and invest in technology
- Impact of Order 636 implementation on the ability to serve new loads, especially electric generation
- Uncertainty of rates charged for gathering services resulting from the unbundling of rolled-in regulated interstate gathering facilities.

The need to improve the transmission and storage system's ability to provide economic, efficient, and reliable service is an extremely serious need for the industry to address. This need is the primary focus of the recommendations in this volume.

RECOMMENDATIONS

Participants involved in the transmission and storage system should take specific actions to improve the system's ability to provide economic, efficient, and reliable natural gas service responsive to customer needs.

Industry and Regulators Should Continue the Evolutionary Process Toward Deregulation in Competitive Markets and Incentive Regulation in Those Markets Where Competition Has Not Been Shown to Exist. Such Initiatives Should Be Structured to Foster Reduced Costs, Increased Efficiency, and Encourage New and Innovative Services That are Responsive to Customer Needs.

Cost-based regulation reduces incentives for pipelines to minimize costs, increase capacity utilization, or introduce new services. Therefore, the industry and regulators should rely on market-based rates in competitive markets and lighter-handed (incentive) regulation should be used in markets where sufficient competition does not exist. Incentive regulation is designed to overcome many of the deficiencies inherent in cost-based regulation and relies upon the belief that the potential for profit is an effective motivator. Among the incentive rate mechanisms widely discussed are Price Caps, Zone of Reasonableness, Bounded Rates, Sharing of Efficiency Gains, and Incentive Rates of Return. For the pipeline industry, incentive regulation can further reduce costs and provide incentives to increase throughput, efficiency, and investments in technology, increasing the flexibility to respond to competition and serve customers, and lowering regulatory and outside services costs associated with current regulatory proceedings. To test this premise, a sensitivity analysis was performed on Reference Case 1 using a compounded 2 percent real reduction in pipeline industry costs. This Case was developed for sensitivity purposes, and is not based on data indicating whether this level of cost reduction will actually be achievable. First realized in 1995, this cost reduction is assumed to result from the impact of incentive regulation and the value created by new flexible services responsive to customer needs. In this scenario, end-use demand increases about 1.7 TCF over the years from 1995 to 2010. By 2010, the pipeline industry's transportation margins are 30 percent lower than in Case 1. Significantly, customers save in excess of $30 billion (1991$) over the 15-year period.

Participants in the NPC focus groups expressed the belief that the gas industry and its regulators show little interest or respect for the needs of its customers. Accordingly, customers are not offered the services that they want and to which they would attribute added value. Consequently, the natural gas industry needs to improve its record of providing the services its customers desire. Fortunately, there are a number of contemporary examples of new services that demonstrate what can be achieved if the proper incentives exist: gas supply aggregation programs, innovative transportation and storage programs, and natural gas vehicle services.

Although NPC study participants expressed concern over rate uncertainty for gathering services, stability in gathering fees for producers and consumers and acceptable economic returns for the owners of gathering systems will best be achieved by open access, unbundling, and market forces. Oversight at the state level may be indicated in isolated cases; but regulation is not an acceptable alternative for the industry where sufficient competition exists.

Industry and regulators should continue the evolutionary process toward deregulation in competitive markets and incentive regulation in those markets where competition has not been shown to exist. Such initiatives should be structured to foster reduced costs, increased efficiency, and encourage new and innovative services that are responsive to customer needs. The impacts of these regulatory changes are expected to include:

- Increased efficiency and reduced costs
- Minimized new facilities requirements
- Lowered regulatory compliance costs
- Increased investments in technology
- Improved ability to serve customers.

The Industry Must Improve Its Ability to Construct New Facilities as Required on a Timely Basis.

The primary hurdle facing the natural gas industry in its attempts to add new facilities remains the ongoing task of providing a framework that maintains equitable cost and risk allocation among producers, pipelines, marketers, and end users. Essentially the risk/return issue is rate/regulatory in nature, and therefore can only be resolved through changes in the regulatory process. The NPC makes the following recommendations:

- The industry should adopt and communicate to its customers a philosophy of **working with customers to install the facilities required for economical, efficient, and reliable customer service.**
- Regulators should establish market-based pricing in markets where adequate competition exists (via negotiated rates)
- Regulators should encourage alternative incentive-based rate structures to mitigate risk conditions in non-competitive markets
- The FERC should establish risk/return parameters at the time of regulatory certification to provide cost assurance.

Present delays in constructing new facilities hinder the pipelines' ability to be market responsive. Environmental review and reporting requirements coupled with the ability of special interest groups and competitors to delay construction through protests and proposals of duplicate facilities act to extend the approval process time to unreasonable extremes. Customers may be drawn to other energy suppliers who require less time to install facilities. Streamlining of the construction approval process would assist the industry's ability to meet customer needs. The industry participants should work with the FERC and other federal, state, and local agencies to expedite the review and approval process for new pipeline projects. Such efforts could include formal agreements between the FERC and appropriate federal and state agencies, establishing coordinated or consolidated procedures that include conflict resolution procedures.

Finding alternatives to high-cost facilities is of paramount importance when customers weigh the cost of gas service against other options. The first step in reducing costs is to minimize new or unnecessary facility requirements. Incentives are needed that encourage the industry to offer new services that meet customer requirements while minimizing the need for new facilities. Efficient use of storage is one alternative to building expensive new facilities. The development and use of new technology should be encouraged to fully exploit improvements in materials and processes to reduce the cost of new facilities and the costs of modifications to existing facilities. The gas industry should specifically work with regulators to create a mechanism to ensure that the benefits of new technology accrue to those who assume the risks and bear the costs. The industry should continue to support the development and deployment of new technologies to meet the needs of the gas transmission and storage industry and its customers, including the development of emission control and retrofit technology for compressor prime movers and more efficient, cleaner burning new prime movers.

The Industry Should Expand Its Work With Customers to Identify and Address Specific Reliability Concerns.

The NPC focus group participants relayed the message that reliability is an important concern and appears to be a major obstacle to greater industrial gas consumption. Reliability covers a broad spectrum of issues including industry communication, operations, regulations, and contracting. The NPC believes the industry has been making a significant effort to address reliability concerns and to develop operating guidelines, but realizes that significant progress remains to be made. Therefore the NPC expands this recommendation as follows:

- The industry should expand its work with customers to address specific reliability concerns by: (1) considering the formation of a national voluntary organization to assist in periods of operating stress, (2) creating an industry master contact list of pipeline and producer operators, (3) coordinating maintenance and downtime schedules, and (4) considering the formation of a Natural Gas Reliability Council to help coordinate and facilitate specific ways to address reliability issues. The industry, perhaps through the Natural Gas Reliability Council, should fully evaluate the recommendations of the FERC/DOE Deliverability Task Force and assist in the implementation of these recommendations as necessary.
- The natural gas industry must overcome a variety of operational conditions to provide the flexible service desired by certain electrical generating requirements. The key to success will be how well each industry understands the other's operation and how well each can integrate that understanding into their own operating decisions to the benefit of both. The natural gas industry and the power generating industry need to make this transporter/customer relationship work through cooperation, coordination, and compromise. The gas industry must develop creative and tailored services to encourage flexibility and commitment to gas by the electric utilities.
- Federal, state, and local officials should support the industry's efforts to address reliability and industry operating guideline issues that improve the overall quality of service to natural gas consumers, including addressing any potential conflicts at federal and state levels between the regulatory framework and contracts.

Industry and Regulators Should Support Efforts to Increase Customer Choices by Increasing Access to Capacity at Both the State and Federal Levels.

- Interstate pipeline customers will soon have available complete open-access, unbundled services, no-notice transportation, and capacity release programs provided by the implementation of FERC Order 636. In order to further the general objectives of the National Energy

Strategy and Order 636, and to encourage the more effective marketing of natural gas services, individual state regulatory authorities need to evaluate and direct, as appropriate, the unbundling of natural gas sales from transmission and storage services by local distribution companies and intrastate pipelines.

- The industry needs to encourage the creation and recognition of market centers as mechanisms to promote better market access and improved reliability of natural gas services.
- The natural gas industry needs to develop better methods to communicate to customers the availability of transmission and storage capacity.

Industry and Regulators Should Make it Easier for Customers to Buy Natural Gas by Supporting Efforts to Develop Guidelines for Operating Procedures.

Each pipeline has its own procedures in place to handle the actual operations needed to move gas, many of which were primarily designed to accommodate the pipelines' own internal needs. Today, customer requirements are vastly different as the customer takes on many of the responsibilities once held by the pipelines. Customers having multiple transportation suppliers find they must operate under different procedures for each. Areas of concern include contracting, nominating, scheduling, balancing, dispatching, and billing. The industry should make it easier for customers to buy and transport natural gas by:

- Supporting the efforts by the Interstate Natural Gas Association of America and the Council of Petroleum Accounting Societies (INGAA/COPAS) and GAS*FLOW User's Group to develop industry operating guidelines
- Simplifying and improving consistency among transportation request forms
- Developing a consistent set of rules governing the allocation of capacity (upstream and downstream) at capacity constrained points
- Improving the efficiency and timeliness of documentation and processing of information through appropriate use of Electronic Data Interchange to transfer information, agreements, and procedures such as operational balancing agreements and predetermined allocation, and on-line real-time measurement.

CONCLUSION

The U.S. transmission and storage system has played and will continue to play a vital role in the nation's energy industry. Just as expansions and improvements have been accomplished since its beginning, new facilities will continually be required and services can always be enhanced. It is the hope of the NPC that the implementation of these recommendations will assist in the realization of the potential of the transmission and storage system as described below.

THE NATURAL GAS TRANSMISSION AND STORAGE SYSTEM PROVIDES ECONOMIC, EFFICIENT, AND RELIABLE NATURAL GAS SERVICES IN RESPONSE TO CUSTOMER NEEDS, ENABLING NATURAL GAS TO MAKE A LARGER CONTRIBUTION TO OUR NATION'S ENERGY NEEDS AND ENVIRONMENTAL GOALS.

ACKNOWLEDGMENTS

This volume was developed by one of four task groups organized to assist the Council in responding to the request of the Secretary of Energy for this study. (See Appendix A for text of the Secretary's letter and description of the NPC.)

The Transmission and Storage Task Group includes knowledgeable and experienced representatives from virtually all major sectors of the natural gas industry, including large integrated companies, independent producers, gathering companies, interstate transmission companies, local distribution companies, industry associations, and government agencies. A full roster of participants is included in Appendix B.

BACKGROUND AND FINDINGS

Chapter One

Background and Overview

Natural gas supplies about 25 percent of our nation's energy needs. Extracted from thousands of wells and consumed by millions of consumers, natural gas is transported almost exclusively by pipeline. In fact, it is perhaps the only industry where the consumer is directly connected to the producer.

From the early 19th century, when both manufactured and natural gas served only small, localized markets, the domestic gas industry has evolved into a complex system linking all lower-48 states. Evolution of the modern interstate pipeline system for natural gas began in the 1920s with the development of high strength steel pipes, which enabled the transmission of natural gas over long distances. From 1930 through the early 1970s, the interstate pipeline system experienced almost uninterrupted expansion. However, since the 1972 peak in consumption, the industry has undergone a period of adjustment to changes in nearly all facets of the gas market.

Historically, pipeline companies bought gas in the field, and resold it in the market area. But over the last decade, this role has changed. Today the primary function of interstate pipeline companies is the long-haul transportation of natural gas. These pipelines provide gas to local distribution companies (LDCs) for distribution to end users, deliver gas directly to large users along the way, and also supply volumes of gas to one another. To do this pipeline companies operate pipeline transmission lines and storage facilities.[1]

The transmission industry supported the market expansion through 1972 with extensive investment in pipeline and storage facilities. The natural gas industry, taken as a whole, has over $112 billion invested in physical facilities to meet these requirements. Of this total, over $50 billion is invested in interstate pipeline and storage facilities.[2] While total domestic consumption has dipped below the 1972 peak, continual adjustment and expansion of the natural gas transmission and storage systems have been necessary to meet the changing regional supply and demand patterns for natural gas.

Pipeline transportation of natural gas is supplemented by underground storage and peak-shaving facilities. Storage fields make a significant contribution to peak-period, especially winter, demands. Peak-shaving facilities, typically operated by LDCs, can provide a significant contribution to peak-period demands as well. LNG, propane-air, and compressed natural gas are used to support hourly swings in demand and to provide short duration peak service, usually limited to a few days each winter season.

---

[1] Underground storage is primarily used to balance seasonal variation in demand and to maintain more efficient gas flows throughout the year.

[2] American Gas Association, *Gas Facts 1990 Data*, Arlington, Virginia (1991). See Tables 13-1 (Total Gas Utility Plant, for investor-owned gas utility industry, total industry) and 13-3 (Total Gas Utility Plant, for investor-owned gas utility industry, transmission companies). These figures represent total cumulative investments, before taking into account accumulated depreciation.

The natural gas transmission system, including storage, is physically a well developed network. However, the industry is currently undergoing a significant restructuring of its business relationships, mandated by fundamental changes in regulatory policies. These regulatory changes are fostering a movement towards market-driven "light handed" regulatory oversight. So-called "light handed" regulation relies on market forces—competition—to achieve public interest goals. As a result, the industry faces a challenging near-term future as it adopts to a more competitive environment.

To put the development of the pipeline industry in perspective, it is useful first to look at events affecting natural gas supply and demand. This chapter provides historical background on the development of the domestic transmission and storage facilities of the gas industry, and then discusses some of the institutional developments that have shaped the way the industry operates.

HISTORICAL DEVELOPMENT OF THE INDUSTRY

The natural gas industry is primarily a domestic industry, with over 90 percent of consumption obtained from domestic sources. All of the natural gas flows by

Transmission and Storage Industry At a Glance

Natural Gas

Supplies about 25 percent of our nation's energy needs. Over 17.3 trillion cubic feet of natural gas was delivered to consumers in 1991.

Extracted from thousands of wells and consumed by millions of consumers, natural gas is transported almost exclusively by pipeline.

The Transmission and Storage System provides the long-haul transportation of natural gas from the production areas to the market areas, delivering natural gas to local distribution companies and end users.

There are about 280,000 miles of interstate pipelines, linking the producing fields with distributors and end users. These individual pipelines are extensively interconnected with each other to provide significant flexibility in the movement of natural gas. Additional connections provide links with Canada and Mexico and terminals provide access to international sources of liquefied natural gas.

These pipelines provide a network capable of delivering natural gas to every state within the contiguous United States.

Because of the extreme seasonal variation in demand, the pipeline system is supplemented by underground storage and peak-shaving facilities. These facilities are used to balance the relatively constant flow of natural gas from the wellhead with the highly variable requirements for natural gas at the burnertip.

There are about 370 underground storage fields in the United States with a working gas capacity of about 4 trillion cubic feet. These fields can provide between 54 and 62 billion cubic feet per day on a peak day, or about 24 billion cubic feet per day on an average winter day. In most cases a storage field is an underground reservoir: a depleted oil field or gas field, an aquifer, or a solution-mined salt cavern.

Peak-shaving facilities (LNG, propane-air, and compressed natural gas stored in aboveground tanks) are used to support hourly swings in demand and to provide short duration peak service, usually limited to a few days each winter season because of the high cost associated with these supplies. It is estimated that over 13 billion cubic feet per day can be provided from peak-shaving facilities.

The industry has invested over $50 billion in these interstate pipeline and storage facilities.

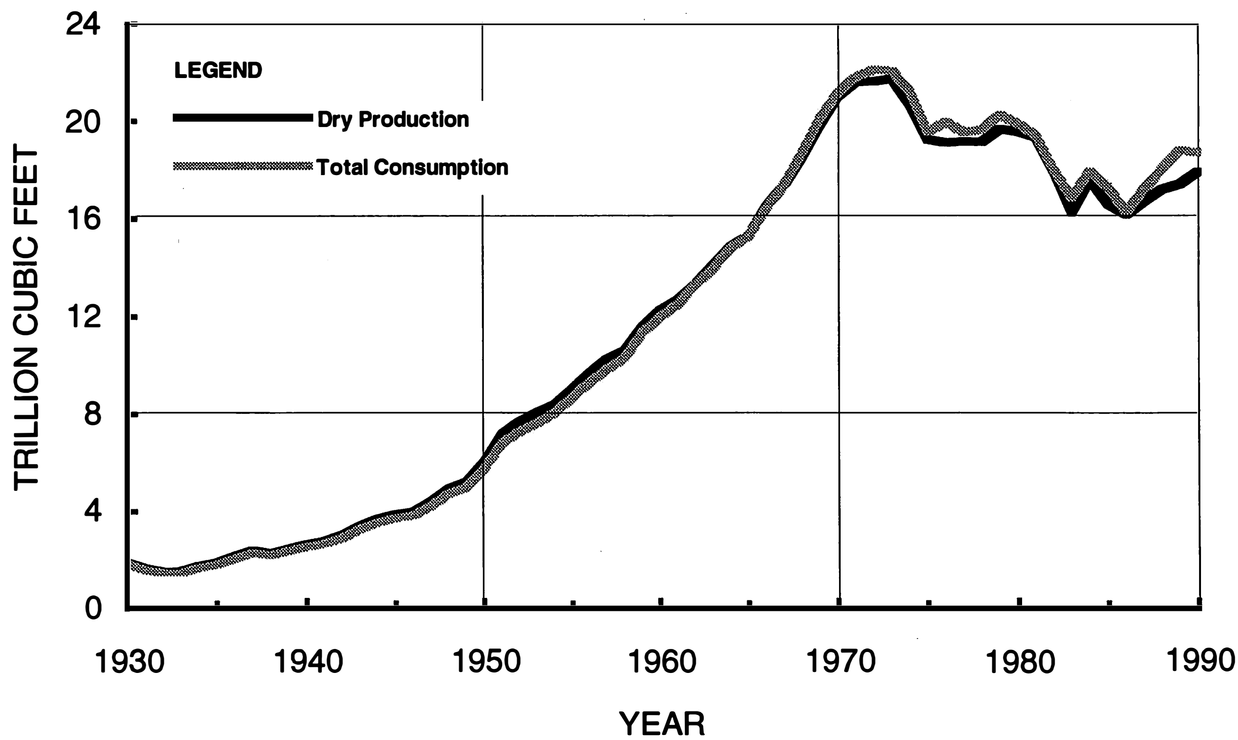


Figure 1-1. Natural Gas Consumption and Production — 1930-1990.

pipeline from the supply source or import point to the ultimate consumer. Most customers of natural gas are located long distances from the supply sources, dictating extensive and flexible delivery facilities. The requirements of the ultimate customers are varied, but can be generally characterized into two classes:

- Seasonal customers, mostly residential and commercial customers, who use natural gas for essential services, such as space heating. Most of their consumption is in the winter season.
- Price-sensitive customers who have the capability to use alternative fuels and can switch based on price differentials. These are the industrial and electric utility customers.

The requirements of the end-use customers vary greatly from day to day and year to year due to weather and business conditions. This requires a flexible transmission and storage system that can adapt to meet the needs of new customers as well as satisfy the extreme variability in demand for natural gas.

Market Development

Consumption

From 1930 to 1990, total natural gas consumption grew at an annual rate of 4 percent, peaking at 22.1 trillion cubic feet (TCF) in 1972[3] (Figure 1-1). After declining to 16.2 TCF in 1986, consumption steadily recovered and by 1991 had increased to 19.2 TCF. Still, consumption in 1991 was about 13 percent lower than in 1972 (Table 1-1).

Price-Sensitive Sectors

Industrial demand led development of the natural gas market and today continues to be the largest consuming sector of natural gas (Figure 1-2). The industrial use of gas peaked in 1973 and then declined sharply; in 1991, at 7.3 TCF, the level was 17 percent less than the peak. This decline was the result of a series of events, including legislative restrictions imposed in 1978 to reduce the use of natural gas (and petroleum products) by electric utilities

---

[3] Not all sectors peaked in 1972. Industrial consumption peaked in 1973 and commercial consumption in 1979.

TABLE 1-1

SUMMARY OF NATURAL GAS CONSUMPTION AND MARKET SHARE BY SECTOR—1930, 1972, AND 1991

	1930	1972	1991*	1991 Percent Change from 1972
Consumption (Trillion Cubic Feet)				
Residential	0.30	5.13	4.57	– 10.8
Commercial	0.08	2.61	2.71	4.1†
Industrial	0.72	8.17	7.25	– 11.3‡
Electric Utility	0.12	3.98	2.79	– 29.9
Total End Use	**1.22**	**19.88**	**17.32**	**– 12.9**
Lease & Plant Fuel	0.65	1.46	1.24	– 14.5
Pipeline Fuel	NA	0.77	0.68	– 11.5
Total Consumption	**1.87**	**22.10**	**19.24**	**– 12.9**
Market Share of Total End-Use Consumption (Percent)				
Residential	24.3	25.8	26.4	—
Commercial	6.6	13.1	15.7	—
Industrial	59.2	41.1	41.8	—
Electric Utility	9.9	20.0	16.1	—
Total End Use	**100.0**	**100.0**	**100.0**	—

NA = Not Available

* Preliminary

† Commercial consumption peaked in 1979 at 2.79 TCF. The 1991 value is 2.6 percent below this 1979 peak.

‡ Industrial consumption peaked in 1973 at 8.69 TCF. The 1991 value is 16.6 percent below this 1973 peak.

SOURCE: Consumption—1930 and 1972: EIA, *Natural Gas Annual 1990*, Vol. 2, Table 3. 1991: EIA, *Natural Gas Monthly*, August 1992, Table 3. Market Share: EIA, Office of Oil and Gas.

and large industrial boilers,[4] the 1982 recession, and later, competition from alternative fuels as oil prices collapsed in 1986. However, the industrial sector again led the post-1986 market expansion, primarily because of increased use of natural gas by consumers with switchable fuel-burning capacity and the development of gas-fired cogeneration. Although the share of end-use consumption accounted for by the industrial sector has declined over the decades (from approximately 60 percent in the 1930s and 1940s to about 40 percent at present), industrial users remain the largest gas-consuming sector. Fulfilling the role of a reliable and economic supplier of fuel to the industrial sector remains a primary goal of the natural gas industry.

The pattern of electric utility consumption generally mirrored industrial usage, but at a lower volumetric level. In 1991, electric utilities used 2.8 TCF of natural gas, approximately 30 percent less than in 1972. Electric utility users,

[4] Powerplant and Industrial Fuel Use Act of 1978.

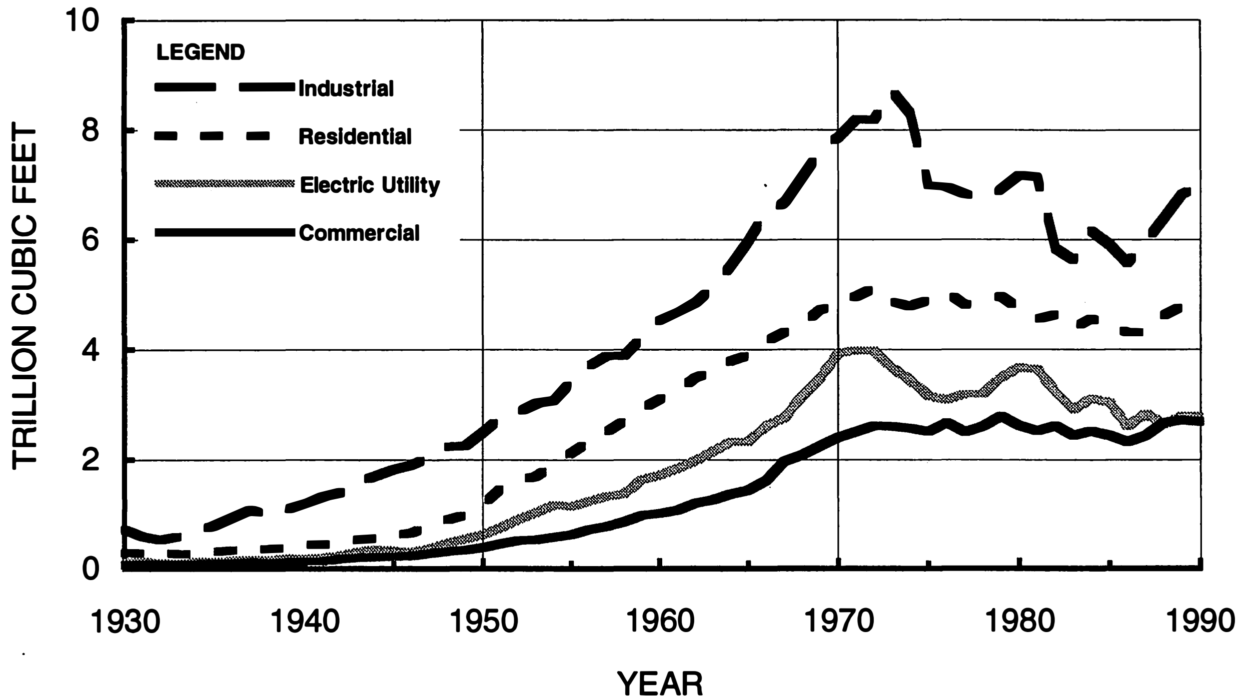


Figure 1-2. End-Use Consumption of Natural Gas by Sector — 1930-1990.

like industrial users, have substantial fuel-switching capability that allows them to respond to changes in fuel prices. During the 1970s and 1980s, as a result of the Powerplant and Industrial Fuel Use Act of 1978 and rapidly increasing prices for both oil and natural gas, electric utilities placed increased emphasis on coal-fired power plants and the development of nuclear power. In 1970, electric utilities paid an average of 12 percent more for coal on a BTU equivalent basis than for natural gas. When measured in constant dollars, gas prices to utilities increased at an annual average rate of 14 percent through 1982, while coal prices increased only 7 percent annually during the same period. Although natural gas prices have dropped dramatically since 1982, electric utilities still paid 58 percent more per BTU for natural gas than for coal in 1990.[5]

Since the late 1970s, almost all baseload generation capacity additions have been either coal-fired or nuclear. Between 1972 and 1989, generation from coal-fired plants more than doubled and nuclear generation increased nearly tenfold, but generation using natural gas decreased by approximately 30 percent.[6]

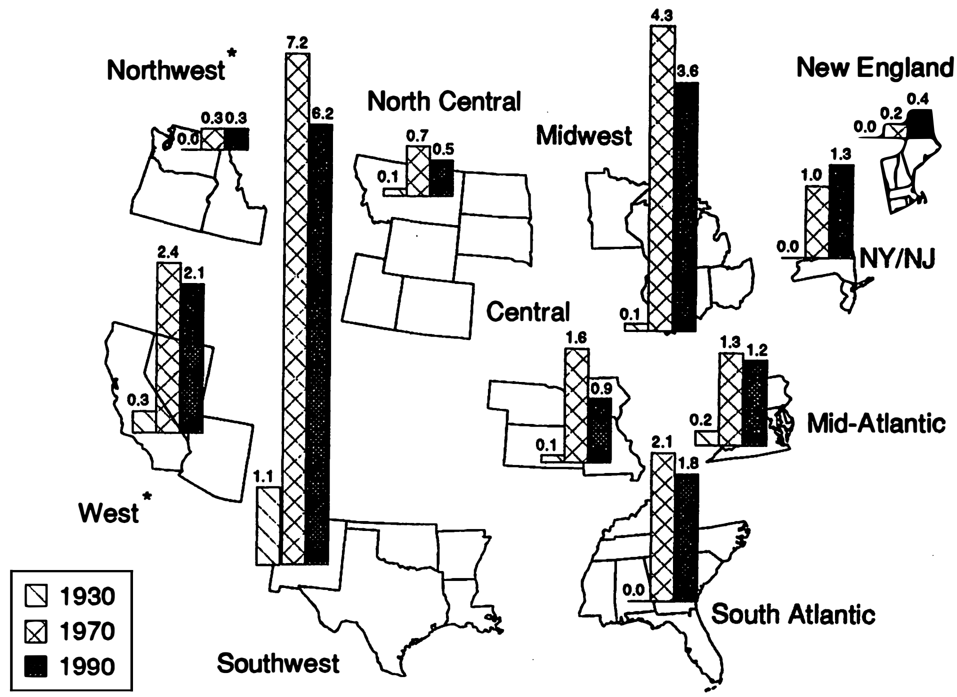
Seasonal Load

Natural gas consumption in the weather-sensitive residential and commercial sectors grew more slowly during the expansion period than in the industrial and electric utility sectors but did not decline as steeply in the post-1972 period. Over much of the 1970s, consumption in these two sectors remained relatively stable. Residential consumption in 1991 was 4.6 TCF, about 11 percent below the 1972 peak. This decline was offset by some gains in the commercial sector. The commercial sector is unique in that consumption in 1991 (2.7 TCF) was slightly above the level in 1972 and close to the peak seen in 1979. Since most residential and commercial customers use natural gas for heating and have limited options for the use of alternative fuels, they are less sensitive to price variations than the industrial and electric utility sectors.

---

[5] Energy Information Administration, "Background on the Natural Gas Industry," *Natural Gas Monthly*, September 1991.

[6] Ibid.



* Excludes Alaska and Hawaii.
Sources: BOM and EIA.

Figure 1-3. Total Natural Gas Consumption by Federal Region (Trillion Cubic Feet).

The decline in residential consumption reflects the countervailing effects of both an increase in the size of the market being served as well as conservation efforts. While the number of residential users has increased by approximately 26 percent since 1972, on average each customer is burning less gas than previously. The impact of generally warmer-than-normal winters in the past few years does not fully explain the change.[7] The primary cause seems to be conservation efforts. These range from cutting back the thermostat, to replacement of inefficient units with more efficient burners, and the incorporation of greater energy efficiency in new homes. The incentive for these efforts are as varied as simply having to replace a unit because of age; the desire to take advantage of tax incentives for weatherization efforts; or response to demand-side management efforts of LDCs. The residential and commercial sectors together accounted for approximately 30 percent of the end-use natural market in the 1930s and over 40 percent from the late 1970s through the present.

Regional Growth

While many regions of the country have had substantial declines in consumption since 1972, the market in the Northeastern United States (the New England and New York/New Jersey regions) continued to expand, led by the electric utility sector (Figure 1-3). Regionally, the Southwest Central and Midwest regions remain the dominant markets for natural gas. However, the Northeast, the area most remote from the supply regions, increased natural gas usage by about one-third during the past two decades and now accounts for about 10 percent of consumption. However, the regional aggregations obscure some important growth areas: in particular, the increasing consumption of natural gas in California to address environmental concerns, and in Florida to meet the electricity generation requirements of a rapidly increasing population.

Supply

Domestic Production and Reserves

Substantial regional shifts are also evident with respect to supply. By 1930, the Southwest Central region had long replaced

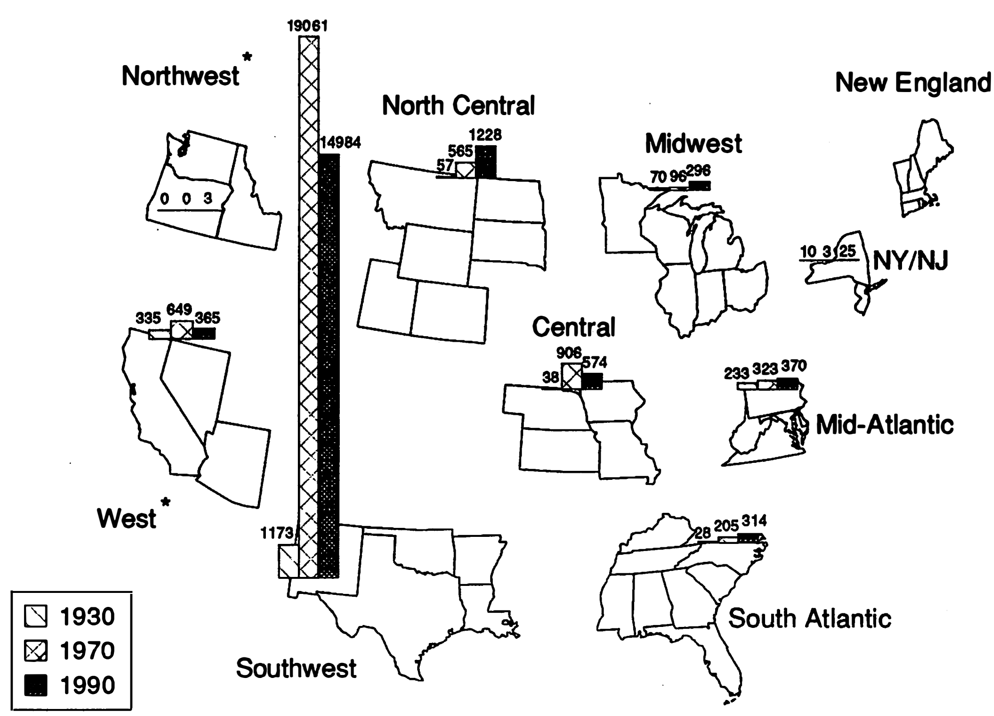
[7] Ibid.

the Appalachian Basin as the dominant supply region, accounting for 60 percent of total U.S. marketed production. By 1970, the region had further strengthened its position, accounting for 87 percent of total marketed production. By 1990, however, while the Southwest Central still accounted for 81 percent of total marketed production, significant supplies—7 percent of the national total—were also available from the North Central region (Figure 1-4). In addition, imports of natural gas from Canada as well as liquefied natural gas (LNG) imports have increasingly contributed to the supply available to the United States.

Natural gas production grew significantly in the United States in order to meet the growing demand for gas. Nationally, dry natural gas production increased steadily, from 1.5 TCF in 1932 to 21.7 TCF in 1973—the year following the historical peak in consumption. While the level in 1991 (17.9 TCF) was substantially below the 1973 peak, production has increased every year since the 1986 low.

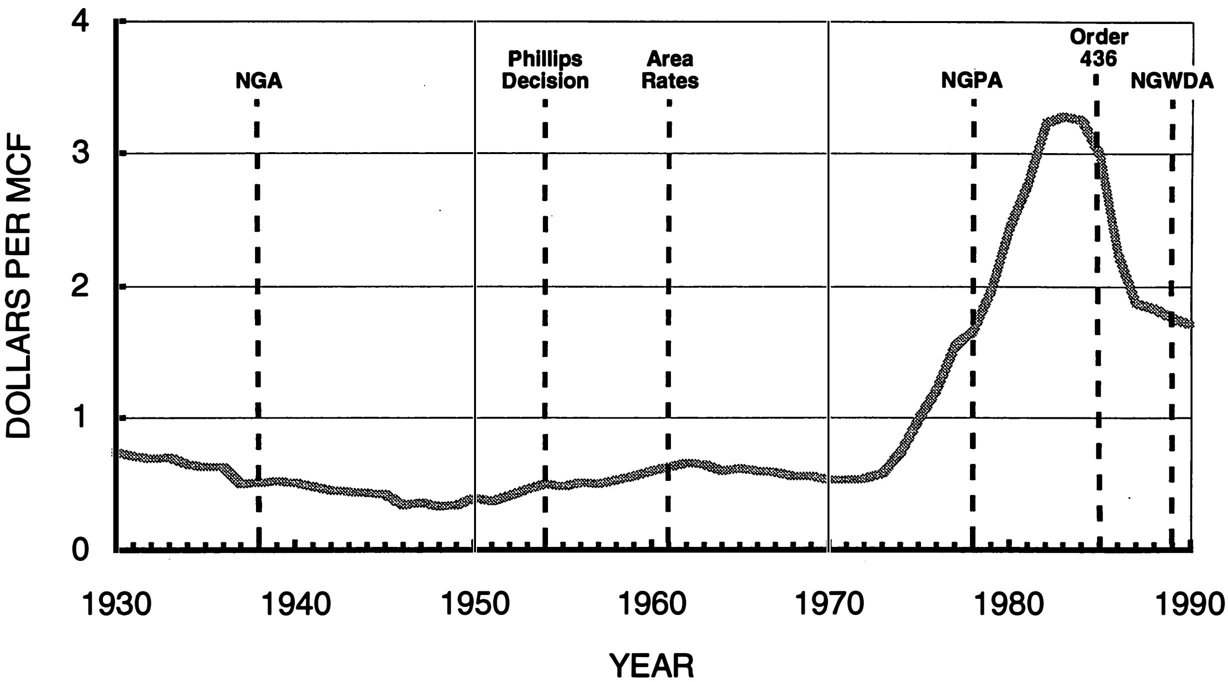
In recent years, abundant supplies and low prices have characterized the supply side of the industry. Active drilling programs initiated in response to the Natural Gas Policy Act of 1978 resulted in surplus wellhead deliverability. This situation was exacerbated and prolonged by several events, all occurring roughly during the same time period. From 1987 through 1990, competitively priced imports increased by 54 percent, warmer-than-normal heating seasons limited natural gas consumption, and entirely new region-specific gas sources, such as coalbed methane were developed. The wellhead price of natural gas in 1990 in real terms had declined to levels last seen in 1978 (Figure 1-5).

Whereas domestic production peaked in 1973, proved reserves of natural gas in the lower-48 states reached a peak of 289 TCF at the end of 1967. From 1967 through 1978, proved reserves in the lower-48 states declined at an average annual rate of 5 percent. This decline was the result of both regulatory and market conditions. In the interstate market, federally regulated wellhead prices often constrained prices to below market-clearing levels. Thus, despite plentiful supplies in intrastate markets, which were not subject to federal price controls, interstate pipeline companies were unable to



* Excludes Alaska and Hawaii.
Note: There is no production in the New England region.
Sources: BOM and EIA.

Figure 1-4. Natural Gas Production by Federal Region (Billion Cubic Feet).



NGA = The Natural Gas Act of 1938.
NGPA = The Natural Gas Policy Act of 1978.
NGWDA = The Natural Gas Wellhead Decontrol Act of 1989.

Figure 1-5. Average Natural Gas Wellhead Prices — 1930-1990 (Constant 1990 Dollars).

compete for these reserves. Reserves dedicated to interstate pipeline companies fell by 80 TCF from the end of 1970 through 1978, accounting for 88 percent of the total decline in lower-48 reserves during the same time period. Eventually, shortages actually appeared in states where supplies were obtained primarily from the interstate pipeline companies. Since the end of 1978, lower-48 reserves have generally declined, but at a much slower rate, reaching a recent low of 154 TCF by the end of 1987. Since then, reserves have recovered only slightly, reaching 160 TCF at the end of 1990.

Imported Supplies

Imports of natural gas, both pipeline and LNG, have played an increasingly significant role in the domestic market. Initially, they were mainly high-priced supplemental supplies to meet increasing demand. Now, however, they are a source of competitively priced supplies, putting increased pressure on the domestic supply market. In 1991, net imports supplied about 8 percent of domestic gas consumption.

Although imports of Canadian natural gas began in the early 1950s, the United States was a net exporter of gas to Canada until 1958. Imports of Canadian natural gas grew steadily until 1973, peaking at 1.03 TCF. In 1973, the average price of natural gas imports was $0.35 per thousand cubic feet (MCF), 59 percent higher than the average domestic wellhead price of gas. During the late 1970s and early 1980s, the price of Canadian gas imports rose dramatically because of regulatory policies tying the border price to the Toronto citygate price. Under this pricing regime, the Canadian export market fared badly as the rigid pricing formula made U.S. imports from Canada increasingly uncompetitive in comparison with domestic sources. In 1982, the Canadian export price peaked at $4.98 per MCF, approximately twice the average wellhead price of domestic supplies. Consequently, imports declined to levels about 20 percent below the 1973 volumes. However, regulatory reforms initiated in 1983, followed by the Free Trade Agreement in 1989, now allow Canadian gas to compete effectively with domestic sources. By 1991, Canadian imports reached 1.6 TCF, recovering from the 0.7 TCF low in 1983.

LNG imports from Algeria were first received at the Distrigas facility in Everett, Massachusetts, in 1971. By 1982, four LNG facilities were operational. Imports peaked in 1979 at 252 billion cubic feet (BCF). By the end of 1985, deliveries were suspended at all of the terminals as the domestic gas surplus and declining gas prices made the imports uneconomic. Distrigas resumed shipments in 1988, and the Trunkline LNG Company reopened its Lake Charles facility in late 1989, receiving a shipment of LNG from Algeria in December. Plans have been discussed for reopening the two remaining facilities at Cove Point, Maryland, and Elba Island, Georgia. The revived LNG industry will differ considerably from the type of operation prevalent in the 1970s. As the world leader in LNG exports, Algeria has moved toward market-responsive pricing coupled with provisions that share the risks and rewards of the marketplace, shifting away from its former system of posted prices as a basis of negotiating contracts. This change is expected to result in more competitive prices for LNG, which like Canadian imports should compete directly with domestic production.

Imports from Mexico have been less significant, peaking at 105 BCF in 1981. No gas has been imported from Mexico since 1984, when imports were 52 BCF. The Mexican government ended exports of natural gas to the United States in November 1984, following a decline in the U.S. and Canadian price indices that set the contract price for exported Mexican gas. The government states that exports will not resume until the price reaches $3.50 per MCF (1991$). Other factors during the 1980s have resulted in a significant increase in exports of natural gas from the United States to Mexico. Exports were in the range of 2 to 4 BCF from 1980 through 1988, then shot up to 17 BCF in 1989. Preliminary estimates put U.S. exports to Mexico at 58 BCF for 1991. The driving force behind this increase has been the inability of Mexican natural gas production, which peaked at 4 BCF per day in 1982, to meet increased domestic demand. Demand has risen because of the increased needs of light manufacturing industries in the north as well as the effort to improve Mexico's environment by substituting cleaner burning natural gas for high-sulfur fuel oil. Given Mexico's reserves base—proved reserves of 71.5 TCF are roughly 40 percent of that of the U.S. lower-48 region—it is anticipated that in the long term, Mexico will again become a net exporter of natural gas to the United States. It remains to be seen whether the necessary capital investment, which has been absent during the 1980s, will be available for the continued development of these reserves.

Seasonality

The annual consumption and production levels discussed above, while important for an understanding of the overall size and development of the market, obscure the seasonal character of the market (Figure 1-6), a critical aspect for the design of transmission and storage facilities.

Approximately 60 percent of gas consumption occurs in the winter heating season (October through March). The residential and commercial sectors are generally served by LDCs and require "on demand" service for heating and other uses. Seasonal variability in the usage of natural gas by these customers is substantial, with peak-month deliveries to these sectors averaging from 4 to 8 times the low-month deliveries. Even during the winter, the peak-day usage can be 1.5 to 3 times larger than the average winter-day requirements.

In contrast, flows from production regions show a limited variability from month to month. During the past 5 years, monthly production has varied from the annual average by no more than 12 percent.

Underground storage is primarily used to balance the relatively constant supply from production regions with the wide seasonal variation in demand. The industry has about 370 underground storage facilities (Figure 1-7), with a working gas capacity of about 4 TCF.

A pipeline company avoids the need to expand transmission capacity from production areas by establishing storage facilities in market areas where there is a strong seasonal variation to demand. By moving gas into storage during off-peak periods, pipeline companies can maintain higher off-peak usage on their trunklines. Thus, storage effectively moves demand from one season of the year to another.

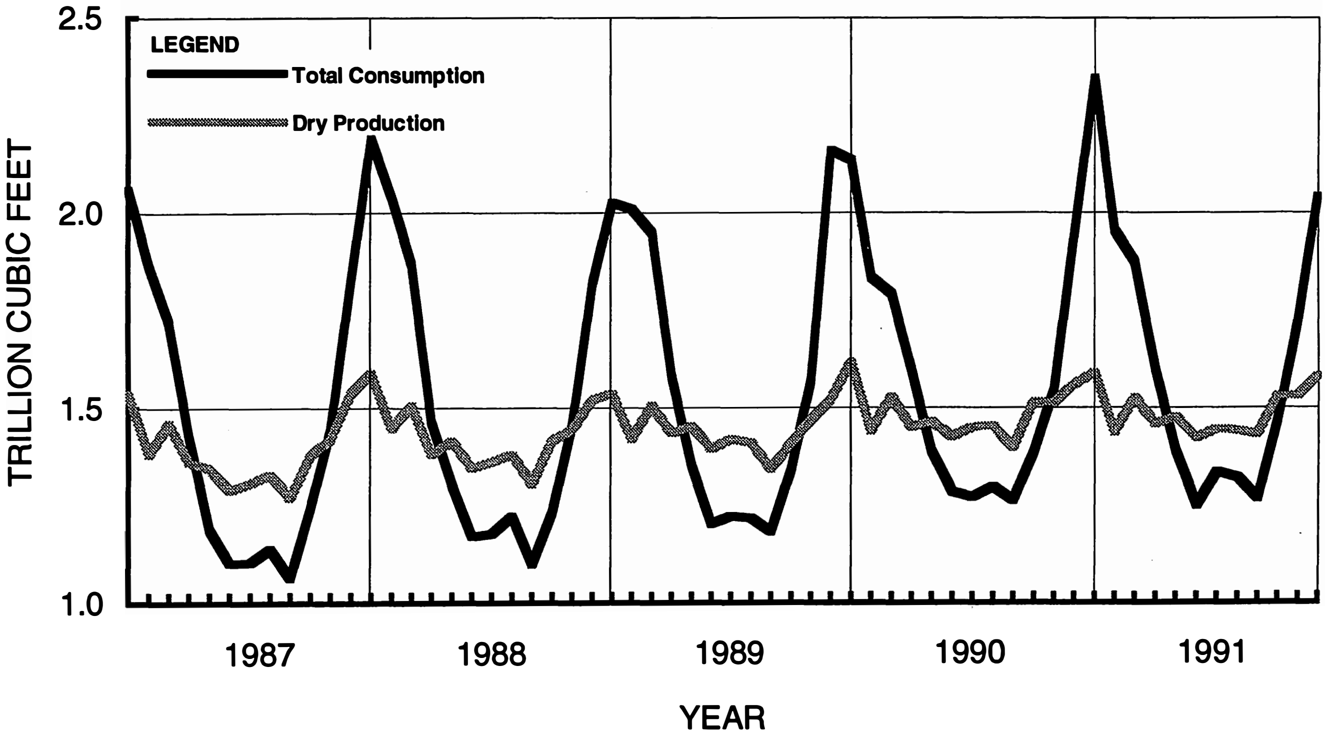


Figure 1-6. Monthly Production and Consumption Patterns — 1987-1991.

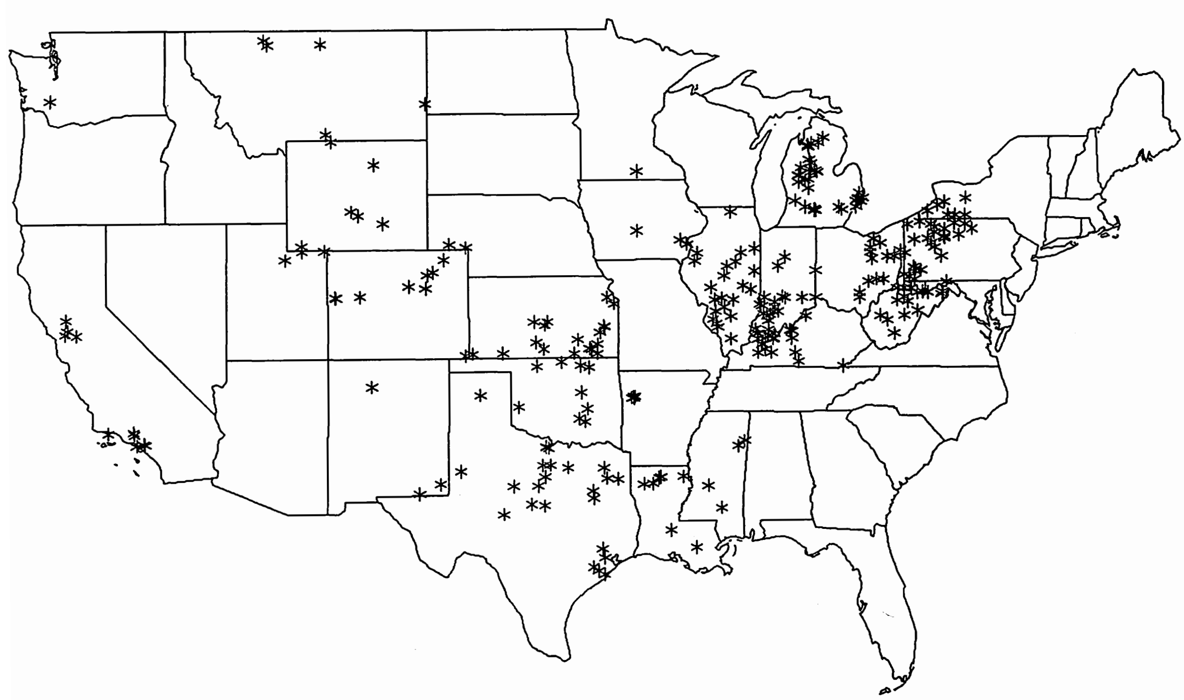


Figure 1-7. Natural Gas Underground Storage Facilities.

Development of the Industry

Patterns of natural gas flows have changed greatly since the 1930s (Table 1-2). At that time, the long-distance pipeline system consisted of only 50 thousand miles of pipe and the markets were very localized. The Southwest Central region was the dominant producer, although 5 percent of its production moved to markets outside the region. The Mid-Atlantic region with the production in the Appalachian Basin was important in the local market serving New York and New Jersey. By 1970, the dominance of the Southwest Central region was evident. However, both the Central and North Central regions were developing greater indigenous sources of supply. By 1990, the North Central region had joined the Southwest Central region as a net exporter of gas to areas outside its regional boundaries.

In the 19th century, the domestic gas industry was dominated by gas manufactured from coal, typically produced locally and used to illuminate urban areas. By the beginning of the 20th century, Pennsylvania and West Virginia were the leading gas-producing states, and small interstate natural gas markets had developed in the Northeast and Midwest. But a series of events soon created an enormous incentive to expand the market. From 1916 through the 1930s, massive natural gas discoveries, including the Monroe, Hugoton, Panhandle, and San Juan fields, vastly expanded available supply and moved the geographic center of proved reserves to the Southwest Central region. The development of high strength welded pipe put this gas within reach of the industrial markets in the Midwest.

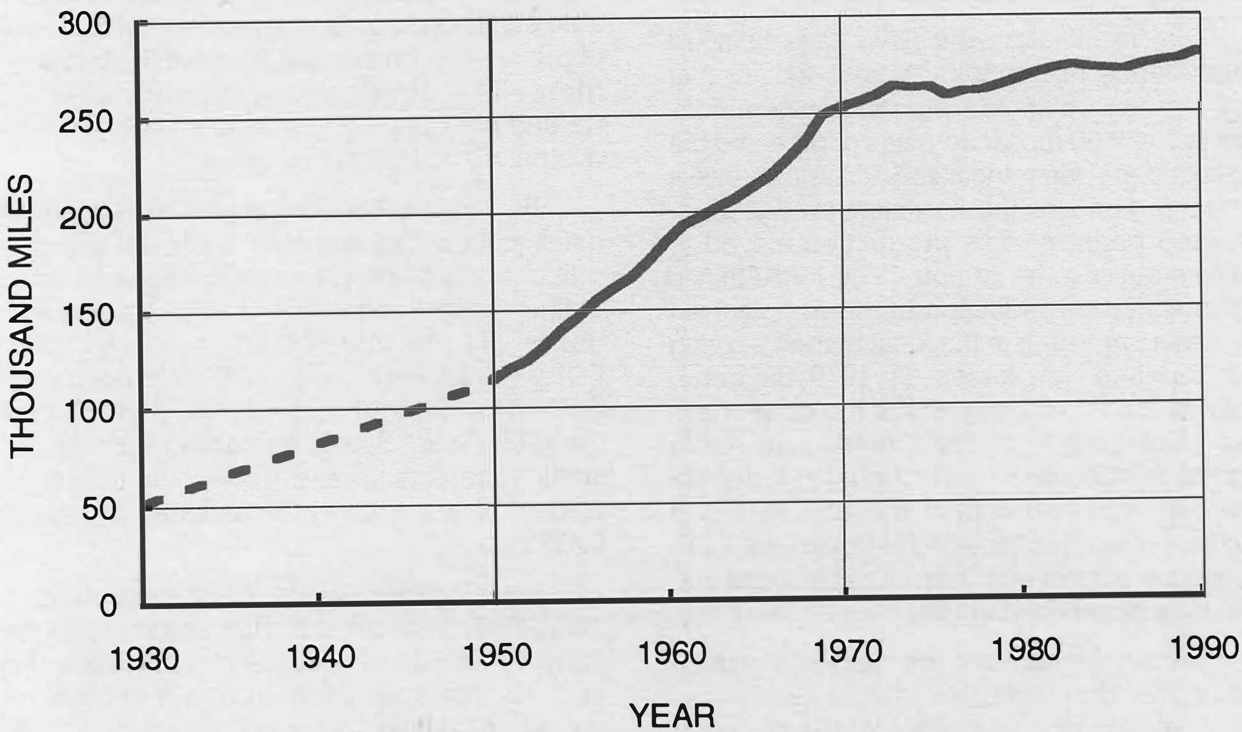
By 1930, when longer-distance pipeline construction had become a proven technology, the interstate pipeline system consisted of four distinct and unconnected regional sections: (1) the Mid-Atlantic area including Ohio, (2) an area essentially connecting the Southwest Central and Central regions with the Gulf Coast States excluding Florida, (3) small segments spread throughout the North Central States, and (4) the intrastate system in California.

Development of the transmission lines paralleled the growth in demand through the early 1970s. Despite the peak in consumption in 1972, regional shifts in markets have required continuing expansion of pipeline facilities (Figure 1-8). Since 1972, the industry has added 22 thousand miles of pipeline and significantly expanded the underground storage systems (Figure 1-9). As gas markets became increasingly seasonal with the growth of the residential and commercial sector, storage located near market centers was needed both as a seasonal supply source and as a safeguard against unexpected supply interruptions.

TABLE 1-2

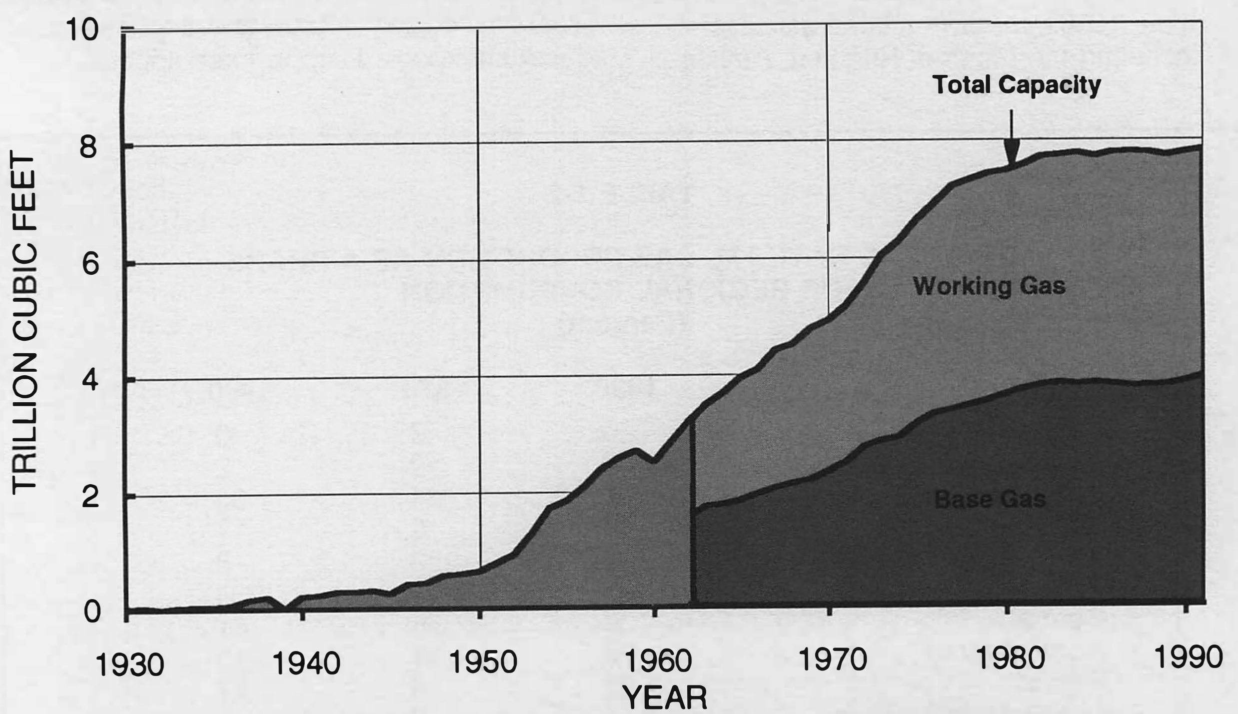
REGIONAL NATURAL GAS PRODUCTION AS A SHARE OF REGIONAL CONSUMPTION (Percent)

Region	1930	1970	1990
New England	0	0	0
New York/New Jersey	49	0	2
Mid-Atlantic	131	24	30
South Atlantic	98	9	17
Midwest	48	2	8
Southwest Central	105	256	234
Central	35	55	61
North Central	76	81	219
Pacific	96	26	17
Pacific Northwest	0	0	1
U.S. Total	**96**	**100**	**97**



NOTE: Data prior to 1950 less reliable.

Figure 1-8. Miles of Natural Gas Transmission Line.



NOTE: Prior to 1962, storage data not distinguished between Base Gas and Working Gas.

Figure 1-9. Underground Natural Gas Storage Capacity — 1930-1991.

Some highlights in the development of transmission and storage facilities are summarized below.

1930s Through World War II

- The initial connections between Southwest Central supplies and Midwest markets were made in 1931 (Natural Gas Pipeline Company of America, Panhandle Eastern Pipeline Company, and Northern Natural Gas Company).
- By 1944, Tennessee Gas Pipeline Company linked the Southwest Central region with Appalachia through a 1,265-mile pipeline.
- Underground storage was first attempted in the 1880s in depleted oil and gas reservoirs of the Appalachian Basin. The first successful underground storage facility in the United States was in Kentucky in 1916.
- Storage capacity increased at an annual average rate of 19 percent from 1930 to 1945, reaching 251 BCF. About half of that capacity was added in the period from 1935 to 1937.

Post-World War II through 1970

- Conversion of the long-distance World War II oil pipelines, Big Inch and Little Inch, to natural gas (Texas Eastern Transmission Corporation) provided the initial connection between Southwest Central supplies and Mid-Atlantic markets in 1947.
- The Southwest Central region and California were connected in 1947 (El Paso Natural Gas Company).
- In the 1950s, new market connections included: North Central producing regions to the Pacific Northwest (Pacific Northwest Pipeline Company), Canada to the northern United States (British Columbia's West Coast Transmission Company), and the Gulf Coast to Florida (Houston Corporation, now Florida Gas Transmission Company).
- By the late 1950s, the domestic natural gas market was no longer separated by the Continental Divide as El Paso Natural Gas Company's connection to the Hugoton-Panhandle field and Northern Natural Gas Company's connection to the Permian Basin created transmission routes connecting the Midwest and the Pacific coast.
- The United States became a net importer of natural gas. The major source was Canada, although some volumes also came from Mexico and from Algeria as LNG. (The majority of natural gas consumed, however, is from domestic sources.)
- Vermont received natural gas service from Canada in 1966, completing the linkage of all lower-48 states to natural gas service.
- Transmission line mileage grew by 4 percent annually from 1950 through 1970, when it reached 252 thousand miles.
- Capacity in underground storage grew by 13 percent annually from 1945 through 1970, when it reached 4.9 TCF.

1970 to the Present

- A unified, national pipeline grid developed with extensive interconnections between systems.
- Transmission line mileage increased at one-half percent annually, reaching 280 thousand miles in 1990.
- Storage capacity grew at 2 percent annually reaching 7.8 TCF in 1990.
- The first LNG facility, Distrigas in Everett, Massachusetts, began operation in 1971. This was followed by the opening of Cove Point, Maryland and Elba Island, Georgia facilities in 1978. A fourth facility was opened in Lake Charles, Louisiana in 1982.

HISTORY OF REGULATION OF THE NATURAL GAS INDUSTRY

Overview

Federal utility regulation of interstate natural gas pipelines stems from the Natural Gas Act of 1938, as amended. These pipeline companies are treated as public utilities with every aspect of their operations subject to regulatory review by the Federal Energy Regulatory Commission (FERC), the federal agency currently charged with regulating the interstate pipeline industry. Since 1978, federal regulation has become increasingly "light-handed," allowing more flexibility for the industry to respond more quickly to changes in the market. The rest of this section will provide a brief summary of the regulatory history of the interstate natural gas pipeline industry.[8]

In its formative years the interstate pipeline industry developed along a simple pattern. Unlike other major transporters in the economy, interstate pipeline companies have traditionally owned the commodity they transported and served as wholesalers between producers and consumers. A natural gas pipeline generally connected a single production area with a single market area. The pipeline would purchase all of the production of that producing field under long-term contracts. In 1954, as a result of the Supreme Court's *Phillips* decision, producer wellhead prices became federally regulated. The pipeline would then resell the natural gas to LDCs in the market region for ultimate resale to consumers. The pipeline's sale of gas was also at a federally regulated price. Pipelines, at times, also sold gas directly to some large consumers and other pipelines. Although the FERC has no rate authority over direct sales of natural gas, it exercises authority over the transportation service aspect of those services.

Typically, a pipeline would transport its own gas for ultimate resale but would not transport for others. Before a pipeline could construct new pipeline facilities, enter into new contracts to buy or sell natural gas, stop providing a service, or change the prices it charged for gas, it first had to receive regulatory approval.

Beginning in 1978 the legislative and regulatory requirements began to change. Faced with persistent shortages of natural gas available to the interstate—but not the intrastate—market and the apparent failure of regulated wellhead pricing, Congress passed the Natural Gas Policy Act of 1978 (NGPA). The NGPA began a program of phased deregulation of natural gas wellhead prices.[9] As implemented by the FERC, this began a period of decreasing regulatory burdens on the interstate pipeline industry. The philosophy underlying the NGPA was that the wellhead market for natural gas was workably competitive and could ensure sufficient supplies at fair prices to everyone. With many producers selling natural gas at the wellhead, price regulation was unnecessary and counterproductive. The NGPA also authorized intrastate and interstate pipelines to transport gas on behalf of other pipelines or LDCs, thus permitting the establishment of a national pipeline system.

In 1985 the FERC issued its seminal Order 436, which fostered a fundamental shift in the regulation and structure of the natural gas industry. The FERC's order implemented a program designed to extend the NGPA philosophy—reliance on competitive markets, not regulation—to interstate pipelines.

The principal element of FERC Order 436 was a voluntary open-access transportation program. Pipelines participating in the program were authorized, on a blanket basis, to provide transportation services on a non-discriminatory basis for any willing shipper, with significantly fewer regulatory restrictions than in the past. Also of importance was a requirement that participating pipelines allow their existing firm sales customers, LDCs, to convert existing firm sales service to transportation service.[10] As shippers, these LDCs would be able to purchase gas from anyone, extending the benefits of a competitive wellhead natural gas market to pipeline sales customers.

Participating pipelines were required to provide transportation, to the extent capacity was available, to any shipper. These pipelines were also allowed, for the first time, to discount their transportation charges to any shipper, subject to a regulated price cap. Under the program, pipelines were prohibited from unduly discriminatory or preferential conduct.

[8] For a more detailed discussion of the regulatory history of the industry see, for example, Arlon R. Tussing and Connie C. Barlow, *The Natural Gas Industry: Evolution, Structure, and Economics*, Cambridge, Massachusetts (1984).

[9] The Wellhead Decontrol Act of 1989 deregulates all wellhead prices by January 1, 1993.

[10] In fact, the original FERC Order 436 program went beyond this to allow existing firm sales customers to phase out their purchase, and the related transportation, from the pipeline over a four-year period. However, this provision, so-called "CD reductions," was invalidated upon court review. In subsequent orders on remand, notably Order 500, *eq seq.*, the FERC terminated the CD reduction program.

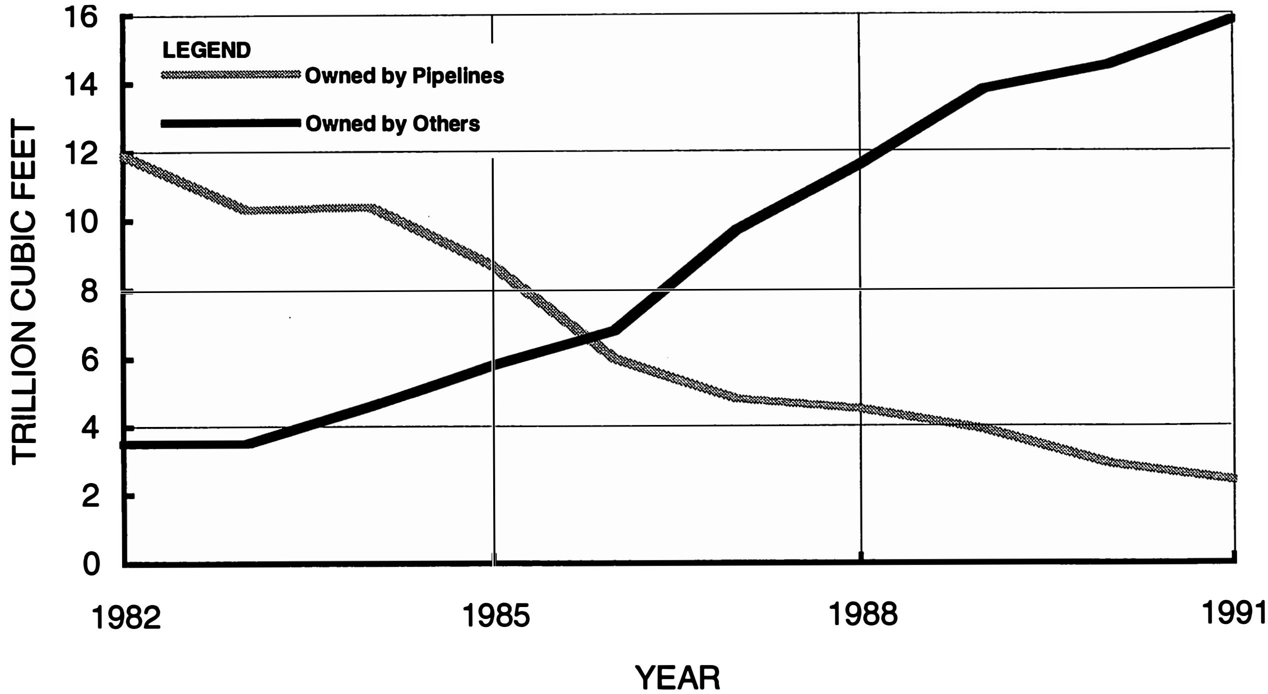


Figure 1-10. Growth in the Interstate Transportation Market: Annual Deliveries by Twenty Major Interstate Pipeline Companies — 1982-1991.

By 1992, over 90 pipelines were participating in the open-access program. Today, nearly 80 percent of all natural gas (transported in interstate commerce) is shipper-owned (Figure 1-10). However, short-term interruptible arrangements account for most of the interstate natural gas deliveries. This, among other factors, led to complaints that open-access transportation was still not comparable in quality to interstate pipeline natural gas sales services. In response, the FERC issued Order 636 on April 8, 1992.[11]

FERC Order 636 mandates the complete unbundling of pipeline gas sales services from transportation services by the 1993-1994 winter heating season. Pipeline companies are required to restructure their contractual relationships with existing firm sales customers, and to offer firm no-notice transportation service in place of firm citygate sales.[12] Pipeline companies are also required to offer storage, gathering, transportation, and sales on a separate unbundled basis. This order, which applies only to open-access pipelines, also removes regulatory price controls from the pipelines' sales of natural gas.[13] After the restructuring process, shippers may continue to purchase natural gas from the pipeline, or from anyone else. Order 636 also mandates a capacity release program, intended to foster a secondary market for pipeline capacity.

It is important to note that Order 636 does not deregulate natural gas services or rates, but instead uses a light-handed regulatory approach that relies more on competition, arms-length negotiated contracts, and prohibitions of undue discrimination. The FERC retains regulatory responsibility over

[11] On August 3, 1992, the FERC issued Order 636A, which modified and clarified some aspects of the original order.

[12] A pipeline's interconnection with a local distribution company is called a "citygate station." This is typically the point where the pipeline physically and contractually delivers gas to an LDC. At that point, title to the gas (ownership) is transferred from the pipeline to the LDC.

[13] This is based on a rebuttable presumption that the pipeline would have no market power over natural gas sales in a competitive environment. This presumption can be overcome by showing that the pipeline is able to exert market power. In this case the FERC may re-regulate that pipeline's sales prices, or take other appropriate actions.

the interstate natural gas industry, but has chosen to exercise these responsibilities in a different way than in the past.

Regulation of Services

As noted above, both the rates and services of interstate pipelines are subject to regulation. Under the Natural Gas Act of 1938, as amended, this regulation takes two distinct forms. First, before a pipeline company is allowed to provide a service, or terminate that service, it must receive authority to do so; this aspect of regulation falls under certificate regulation.[14] Second, before a pipeline company may change a rate, or modify the service itself, it must also receive regulatory authority; this later aspect of regulation falls under tariff regulation.[15]

Historically, new services subject to these regulatory requirements required separate authority for each new service, provided for each customer. Regulatory proceedings often required significant amounts of time to resolve. However, as the number and complexity of these filings increased, the time required became a significant burden to both regulators and regulated companies. Also, the types of services involved tended to be rigidly structured: producers selling to pipelines (after 1954); pipelines selling to pipelines; and pipelines selling to distributors. Within this framework, the industries' ability to react to changing competitive circumstances and to innovation was limited.

In response, regulators began to experiment with so-called "blanket certificate authority." Under this concept, pipelines were authorized, within prescribed limits, to undertake activities on a generic basis. Upon receipt of this blanket certificate authority, pipelines were allowed to "self-implement" authorized individual activities without prior regulatory review. Beginning with annual "budget blanket certificates," pipelines were allowed to build new facilities to connect to new supply areas. This concept was expected to provide for a one time blanket certificate to permit (a) the construction and operation of certain facilities subject to cost limits, and (b) other activities, either on a self implementing or prior notice basis. After 1978, the FERC began authorizing blanket service authorizations for the transportation and sales of natural gas for other interstate pipelines and local distribution companies. In 1983, this blanket authority was broadened to allow limited service for direct end users as well. Since 1983, the scope of blanket transportation authority has been expanded to allow greater flexibility for the pipelines to offer services, and to discount their rates to meet changing market conditions.

Another aspect of service regulation involves pipeline tariffs. Tariffs are public documents that describe the services offered by an interstate pipeline, and the terms and conditions under which these services will be provided. These tariffs also contain the charges that apply to each service. Before a pipeline company may change a tariff it must first provide 30 days notice to the FERC and to its customers. In practice, these tariffs are usually contested. This leads to requirements for suspension, subjecting the increased charges to refund pending the outcome of a hearing.

Traditionally, pipelines sold or transported gas, or provided storage services under case-specific, customer-specific tariffs (called rate schedules). The specific rates and terms and conditions of service were tailored to the service offered to specific customers.

However, paralleling the changes in service authorizations noted above, tariffs have become more generic. Today, most pipelines offer and provide services under open-access rate schedules. These rate schedules provide generic terms and conditions of service that apply to all shippers. These rate schedules also contain the maximum and minimum rates that a pipeline may charge. Within the specified range, a pipeline may agree to provide service at any price; however, the pipeline is

---

14 Interstate pipelines are required to receive authority under section 7 of the NGA before providing any new service for any individual customer (a "certificate of public convenience and necessity"), and before abandoning any service (abandonment authority).

15 An interstate pipeline company is required to file proposed rate changes, or tariff (service) changes, with the FERC, at least 30 days prior to their proposed effective date. Should any party object, or on its own motion, the FERC may suspend these rates for 5 months pending the outcome of a hearing. Any rates suspended by the FERC may only be collected, after the suspension period, subject to refund, upon conclusion of the hearing. These filings are subject to the "just and reasonable" standard, and procedures proscribed by Section 4 ofthe NGA.

not required to provide service at a discount unless it chooses to do so, on a non-discriminatory basis. In any case, the rates charged, and the application of terms and conditions of service are subject to a condition that prohibits undue discrimination.

Rate-Making Concepts

Historically, pipeline rates have been regulated on a cost-based concept.[16] Regulators base approved rates on the original cost of the facilities used to provide the offered services. The "cost-of-service" includes: depreciation expenses; operating and maintenance expenses; administrative and general expenses; taxes; cost of debt; and an approved return on stockholders' investment. The approved return on equity is based on the undepreciated original cost of construction, expressed as a percentage of that investment, and related income taxes. These costs are then classified between fixed costs (those that do not vary with use) and variable costs (those that are dependant on utilization, such as fuel).

Once the cost-of-service has been determined, these costs must be partitioned among the various services offered by the pipeline, and rates designed. This process is called allocation and rate design. In simple terms, costs are functionalized (divided into functions such as gathering, storage, transmission, and sales), allocated between services and zones, and rates are derived from the allocated costs. In short, the costs are divided by the projected units of service.

Historically, regulators have used the allocation of fixed costs (which include return on equity and related taxes) between the reservation fee and the unit charge to react to competitive changes in the market. Greater allocation of fixed costs to the unit charges tends to reduce demand, whereas a lesser allocation of fixed costs to the unit charges tends to stimulate demand. Historical patterns have shifted from recovery of all fixed costs in the unit charge (the so-called 100 percent volumetric rate), to the current preference for recovery of most fixed charges in the reservation fee. Throughout this period, regulators have continued to allocate fixed costs to interruptible services, at times using different formulas to vary the amount allocated.

It is important to note that cost-of-service regulation does not ensure that a pipeline company recovers all of its costs. The projections of costs and volumes of service, and product mix among services, determines the pipeline's ability to recover its allowed cost-of-service. Depending on actual cost, volumes, and product mix, pipelines can generate revenues above or below their authorized cost of service. Generally, revenues above the authorized cost of service are not refunded and revenues below the authorized cost of service are not recoverable in a subsequent period.

During the early years of interstate pipeline regulation, natural gas purchase costs were treated as any other variable cost. However, subsequent to 1954, gas purchase cost increases lead to an increased frequency of rate increase filings with regulatory agencies. This lead to the eventual adoption of "purchased gas adjustment" mechanisms to pass gas costs directly to customers. A purchased gas adjustment is a mechanism that is intended to ensure that the pipeline (or LDC) recovers its purchase gas costs, and that customers are given more accurate, more current, price signals. True-up mechanisms are employed to prevent the pipeline (or LDC) from making a profit from the operation of the mechanism—underrecovered or overrecovered costs in one period are recovered (refunded) in the next through surcharge mechanisms.

Construction Permits

The FERC has also developed complementary regulations to simplify the approval process for the construction of facilities. Since passage of the Natural Gas Act, interstate pipeline companies in most cases have been required under Section 7(c) of the Act to obtain a certificate of public convenience and necessity before constructing pipeline facilities. Once a project is approved and constructed under a Section 7(c) certificate, the costs of the facilities are usually eligible for inclusion in the pipeline company rate base (when the company files its next general rate case) and the risks associated with recovery of those costs

[16] These principles have also applied to the rates of other regulated utilities, such as LDCs.

Options for Approval of Interstate Facilities

Natural Gas Act Section 7(c). The pipeline company is typically required to demonstrate that it has service commitments to customers in sufficient volumes to justify the investment in facilities construction and that it has access to sufficient natural gas reserves to meet its customers' requirements. While this was historically the first and therefore has been the most frequently used method of obtaining certification, the Section 7(c) process is often time-consuming and complex.

Blanket Certificate. A blanket certificate approves a series of similar actions in one authorization and can be used for relatively small projects. Blanket programs started in the 1970s with "budget blanket gas supply" programs and expanded in 1983 with Order 234. In recent years, the FERC has been using blanket certification more frequently to authorize and facilitate both construction projects and transportation programs.

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

Optional Expedited Certificate. In 1985, under Order 436, the FERC introduced Optional Expedited Certificates whereby construction could be approved without assessment of its financial soundness. In return, the pipeline company agrees to bear the majority of the risk of the project. Furthermore, the pipeline company may not decrease the projected volume of services used to design rates nor shift costs to pre-existing customers.

are minimized.[17] Besides review of operational aspects of the system, other legislation requires extensive review of the environmental aspects of the projects.[18]

Concern about the length and complexity of the review procedures led the FERC to develop alternative procedures to simplify the process and allow quicker expansion of the systems. These include "blanket" certificates for projects below a certain size, as well as expedited clearances for construction where the pipeline is willing to assume the risk of cost recovery of the investment. The text in the box above provides more detail on the certification options available to interstate pipeline companies. During the 1980s, the Section 311 procedures were used extensively but the traditional 7(c) application is still the most widely used.

In September 1991, the FERC issued Order 555, which substantially modified construction authorization procedures and environmental regulations in a further attempt to streamline the review process. However, in November 1991, the FERC indefinitely postponed the effective date of the order in response to numerous requests for rehearing.

NATURAL GAS PIPELINE AND STORAGE OPERATIONS

The interstate natural gas industry began in the 1930s. Producers would sell their gas to interstate pipeline companies in the field. The pipeline companies would transport it across state lines, and resell it to distribution companies at federally regulated prices. Distribution companies would resell the gas to consumers at state-regulated prices. In short, companies bought and sold natural gas. Where trans-

---

17 The FERC may also issue a Section 7(c) certificate subject to "at risk" conditions. In such cases, the companies are not guaranteed authority to include costs in the rate base, and the risk is minimized only when contracts are in place for all the capacity of a new line.

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

portation was involved, companies only transported for themselves. And only three types of companies were involved: producers, pipelines, and distributors. Every transaction was subject to regulatory scrutiny, and, in most cases, required prior regulatory approval.

Today the natural gas business is significantly more complex than it was in 1938. Anyone can buy—or sell—natural gas at the wellhead, or anywhere else. Each component service, from gathering to transportation, can be purchased separately from a number of competing vendors. And in many cases the vendors' prices are not regulated by federal or state authority. Even where a service continues to be regulated, the vendor often has "blanket authority" to provide a service to any willing purchaser within preset parameters.

Pipeline Operations Under Traditional Regulation

Pipeline operations under traditional regulation were simple compared to operations under today's open-access program. Formerly, producers sold to pipelines, who sold to LDCs, who sold to consumers. Long-term contracts were extensively used, resulting in relationships that were two dimensional and stable. (See Figure 1-11.)

Before open access, pipelines generally played a central role as the primary middleman between producers and LDCs. Individual pipelines were often the only seller to an LDC in the marketplace. This also meant that pipelines had relatively few parties at each end of the system with which to coordinate. Operationally and contractually the pipeline had total control over the natural gas flowing into, through, and out of its facility.

In summary, under traditional conditions:

- There were relatively few parties involved in transactions and operations
- Pipelines held total contractual and operational control over their pipeline systems
- Contractual relationships tended to be independent, two-party, and long-term.

Pipeline Operations Under Open-Access Regulation

Today, pipeline operations are not so simple. Whether buyer, transporter, or seller,

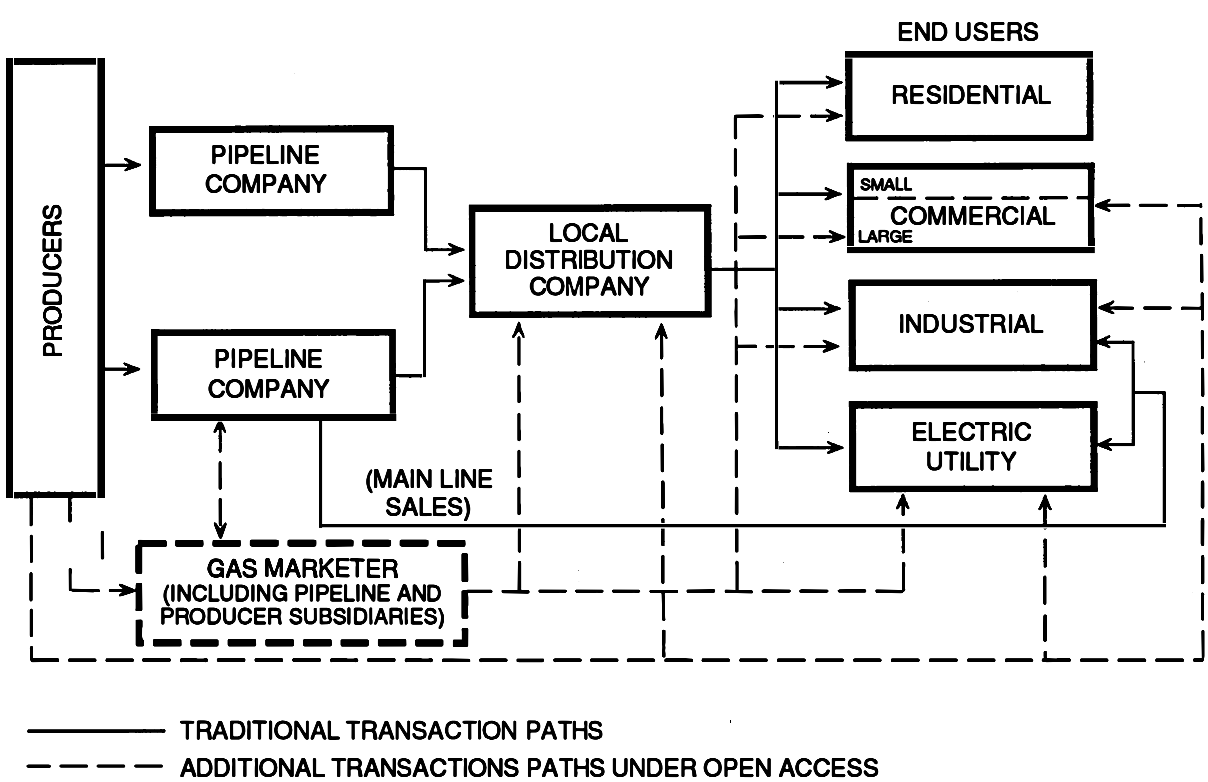


Figure 1-11. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing.

everyone faces an unlimited number of potential trading partners. Gas sales are typically done on a 30-day basis. Contractually, many parties may be involved between the wellhead and the burnertip in the sale and transportation of natural gas. Operations require the coordination of many parties, and the matching of gas flowing into and out of the pipeline system. Pipelines' operational autonomy has been replaced with contractual and tariff based controls.

Pipeline operations are under tremendous pressure to accommodate these changes. The shift from sales to transportation requires pipelines to pay close attention to gas flows into and out of their systems. Pipeline operating functions that were internal management functions under traditional regulatory schemes are now externalized through tariffs and contracts.

In summary, under "light-handed" regulation:

- There are many active parties involved in the sale, transportation, aggregation, marketing, and delivery of natural gas.
- Pipeline operations are subject to external control through tariffs and contracts.
- Purchasers bear many of the responsibilities previously held by the pipelines in managing supply portfolios, arranging delivery, and balancing purchases with demand.
- Contractual relationships tend to be market-driven, multi-party, and short-term.

FERC Order 636 has several provisions that will have a significant impact on pipeline operations. Unbundling, no-notice service, and capacity release are the most significant of these new requirements. These changes will further reduce the integration of pipeline operations. As a result, pipelines will be required to offer a menu of services, while customers (now "shippers") will be required to take on some of the functions formerly performed by the pipelines (or to delegate these functions to "agents").

Unbundling requires pipelines to separate their merchant sale of natural gas from the transportation service. After unbundling is complete, pipelines will be required to sell gas as it enters the system. The pipelines' current firm sales customers will become firm shippers on the pipeline, subject to advance nomination and scheduling requirements, balancing, and other operational controls.

Pipelines will be required to offer "no-notice" transportation service. This service is required to be equivalent to the transportation/delivery service previously provided by pipelines as an integral part of their citygate sales service. To provide this service, pipelines will have to re-examine their operations, and adopt contractual and tariff provisions defining the service, and ensuring a capability to deliver daily requirements on demand. While no-notice shippers will be able to take what they need on a daily basis, they will still be required to maintain an adequate gas supply, and balance pipeline receipts and deliveries on a monthly basis.

To provide no-notice service, pipelines will have to balance the physical unbundling of the system, with tariff provisions and shipper cooperation. There are many ways pipelines may achieve this result:

- Retaining control over a portion of storage capacity
- Operational control orders (giving the pipeline the power to tell shippers where and when to inject gas into the system, under prescribed circumstances)
- Improving communications and cooperation among producers, shippers and the pipelines
- Flexible use of contract storage for system operations
- Constructing new facilities (including SCADA systems[19] at receipt and delivery points and new pipeline and storage facilities).

Pipelines are also required to unbundle storage services, to the extent not needed to provide operational flexibility and no-notice transportation. This will reduce pipelines' control over storage injections and withdrawals, while giving shippers a significant tool in managing their own gas supply.

---

[19] SCADA (supervisory control and data acquisition) systems are electronic measurement and control equipment that allow the pipeline from a central location to monitor gas flow at specific points, and adjust that flow as circumstances require.

Another significant feature of Order 636 is the capacity release program. Pipelines are required to establish and maintain electronic bulletin boards where firm shippers can post notices of surplus capacity. Once posted, any willing replacement shipper may bid for the offered capacity. The highest bidder will sign a contract with the pipeline, and become a shipper in its own right. The releasing shipper will receive a credit on its monthly bill once service begins to the replacement shipper. Pipelines may also seek to market released capacity, in exchange for agreed upon compensation (essentially a capacity marketing fee). The pipeline is allowed, but not required, to permanently release the original shipper from all obligations under the prior contract.

The release program should free up some unneeded capacity for use by new shippers. Also, the release program would allow a releasing shipper to offer capacity subject to certain conditions. These conditions may include a reversion trigger (during cold weather), other specific recall rights, or seasonal limitations, among other options.

Specific Challenges of Unbundled Operations

With increased opportunities come increased responsibilities. Those who wish to enter the competitive marketplace find that they must take on significant new responsibilities formerly provided by the pipeline. These responsibilities include: supply planning and aggregation; communication and coordination; storage management; flow monitoring; contingency planning; and balancing receipts into and deliveries from the pipeline system.

Supply aggregation will no longer be the sole responsibility of the pipeline. In most cases, an individual shipper's portfolio will be significantly smaller than that previously maintained by the pipeline.

Communication among producers, aggregators, pipelines, and consumers is an essential element of the transportation service. Shippers will have to communicate with suppliers and pipelines so that gas flow matches demand.

Shippers will also have to balance their own supplies going into and coming out of the pipeline. Because there are many shippers, and because the shippers—not the pipeline—control gas supplies, balancing is an essential requirement of transportation service. Beyond a minimal level, one shipper's imbalance will directly affect other shippers' service.

Pipelines have begun to offer new innovative services to meet different shippers' requirements. These services include off-peak firm transportation, open-access storage, market-priced gas sales, and others. Pipelines must balance the operational requirements of these services. Shippers must make choices of which service, or combination of services, best meets their needs.

SUMMARY

Since 1985, with Order 436, and continuing today, with Order 636, the interstate natural gas industry has undergone significant changes in market structure. The industry is no longer locked into the rigid commercial relationships of the past. Competition among natural gas sellers has expanded, as has competition among pipelines.

The early expansion of the industry was supported initially by regulation providing for stable prices, assurance of adequate supplies to justify the large capital investment, and the recovery of costs associated with these capital investments. In general, federal regulations provided extensive direction and oversight of the natural gas industry. With the development of a mature and integrated pipeline system and competitive markets at both the wellhead and end-use sectors, the need for more market flexibility has been recognized and implemented in the recent industry restructuring orders issued by the FERC.

In summary, the major regulatory changes that have taken place since the early 1980s have allowed:

- Pipeline companies to unbundle services, setting rates for sales, transportation, and storage separately, thus allowing customers to select the services they want from a slate of options.
- Pipeline companies to vary rates in order to retain price-sensitive customers and thus maintain load.

- Pipeline capacity to be available to all shippers on a nondiscriminatory basis, greatly increasing the number of participants in the market and the transaction paths available.
- Development of a secondary market for pipeline capacity through "release programs" leading to fuller utilization of capacity.

A large proportion of pipeline companies' traditional customers have changed their service from firm sales to firm transportation, shifting the role of the pipeline company from one of a broker of natural gas to that of a transporter.

The increasing regulatory flexibility allowed under the recent FERC orders provides substantial opportunities for participants in the natural gas market. While the structure appears to be increasing the efficiency of price signals, the costs of this transition have been significant. The most visible costs are the $9 billion of take-or-pay settlements. Pass-through of these costs, which were incurred in the 1980s, will continue well into the 1990s.

With these opportunities come increased risks and responsibilities. While the federal regulatory policies are being developed to permit the market to act in those areas where "workable competition" can be demonstrated, legislation remains in effect that requires "just and reasonable" rates and nondiscriminatory access. The debate will continue as to the best ways to compensate the industry for innovation and efficiency in service and yet fulfill the obligations required under the provisions of the Natural Gas Act.

CHAPTER TWO

FINDINGS

Key findings of a review of the existing transmission and storage network are:

- The existing system is a valuable asset that plays an integral role in the development of the U.S. energy industry.
- The existing system can support a growing U.S. natural gas market.
- There will be a continuing need for the construction of new facilities to adapt to changing supply and market patterns; the estimated cost of this construction is in line with past experience and should not be a major constraint to future industry growth.
- The natural gas transmission and storage system has—and continues to improve—the ability to provide economic, efficient, and reliable service responsive to customer needs.
- The natural gas transmission and storage system needs to further improve its ability to provide economic, efficient, and reliable service responsive to customer needs.

Each day natural gas is produced, transported, distributed, and consumed in millions of homes, offices, and factories. Over 19.2 trillion cubic feet (TCF) of natural gas was consumed in 1991—an average of nearly 53 billion cubic feet per day (BCF/D). Because natural gas is used extensively to heat homes and businesses during cold weather periods, actual consumption on a very cold day may be considerably higher. Natural gas delivery facilities are designed to accommodate the maximum amount that may be required to meet peak-day demands.

An extensive natural gas delivery system has grown over the last 60 years to meet these demands. Individual natural gas wells are connected to gathering systems, which aggregate and deliver it to an extensive network of intrastate and interstate pipelines. The pipelines transport the gas at high pressures across often long distances and redeliver the gas to local distribution companies and large end users.

This chapter focuses primarily on the interstate pipeline network and extensive storage facilities developed as a supplement to wellhead supplies to meet peak-period demands. The National Petroleum Council has performed an extensive review of the capability of the transmission and storage network. The key findings resulting from this review are summarized in the shaded box to the left. Each of these findings is addressed in the following sections of this chapter. This material will provide a point of departure for the discussion of issues and recommendations elsewhere in this volume.

The Existing System is a Valuable Asset That Plays an Integral Role in the Development of the U.S. Energy Industry

The interstate pipeline network currently totals nearly 280,000 miles of pipe. More than 370 underground storage facilities provide a valuable supplement to the pipeline network. Together, investment in these facilities exceeds $50 billion (balance at the end of 1991).[1] The interstate pipeline network provides service to all 48 of the contiguous United States. This allows for continuous reliable service to over 54 million residential and small commercial customers.[2]

The existing system provides a valuable infrastructure capable of supporting continued economic expansion of natural gas markets. Replacing this system today, in current dollars, would cost significantly more than the $50 billion invested. Further, a substantial portion of this investment has already been depreciated, leaving a net book investment less than half of the original cost of construction. Existing pipeline facilities are expected to remain in service well into the next century.

The Existing System Can Support a Growing U.S. Natural Gas Market

This section examines the capabilities of the existing transmission and storage network. First, interstate pipeline capacity and regional storage capabilities are summarized. Second, this information is examined, along with additional information on regional production, consumption, peak shaving, and imports, to derive estimates of national peak-day and annual delivery capabilities. Finally, these capabilities are compared to estimates of current consumption to determine the ability of the existing system to support market growth.

[1] Source: Federal Energy Regulatory Commission Form 2, *Major Pipelines*, 1991.

[2] American Gas Association, *Gas Facts 1991*, Arlington, Virginia (1991), p. 97.

Capability of the Existing System

The existing pipeline and storage network has evolved over more than 60 years. From its inception, the pipeline industry has designed and constructed facilities adequate to meet firm contractual commitments. However, as they evolved, pipeline operations and capacity assessments have become more complex.

The NPC studied the capabilities of the existing interstate pipeline and storage network. The current inter-regional capacity of 37 interstate pipelines was examined using 1989 as a base year.[3] Figure 2-1 illustrates the regions used in this study. The capacity of each of these pipelines was determined where they crossed the boundaries of each region. Also, the capacity of the existing underground storage fields within each region was compiled. Additional information was collected for pipeline capacity additions through 1991; planned additions for 1992 through 1994 were examined as well. Included in these data are figures for projects that have been approved by the Federal Energy Regulatory Commission (FERC), but have not yet been constructed. Detailed data on the Existing System Study is found in Appendix C.

The pipeline data were initially compiled from FERC records.[4] Copies of the draft data were then circulated among members of the Transmission and Storage Task Group for review. The storage data was compiled from FERC records and from the American Gas Association storage database. In addition, Interstate Natural Gas Association of America sent a survey of the draft pipeline and storage data to member pipelines for review and confirmation. The Task Group members also solicited confirmation of storage figures from intrastate operators.

A summary of the results of this study is shown in Table 2-1 for 1991. The Southwest Central and North Central regions produce most of the domestic natural gas supplies for

[3] Use of 1989 as a base year was required to be consistent with the high and low reference case demand and supply modeling efforts. This also provides a point of departure from the last NPC capacity analysis in 1988.

[4] These records included Exhibits G, G-I, and G-II from applications before the FERC, supplemental flow information filed in these applications, and Form 567 annual flow diagrams.

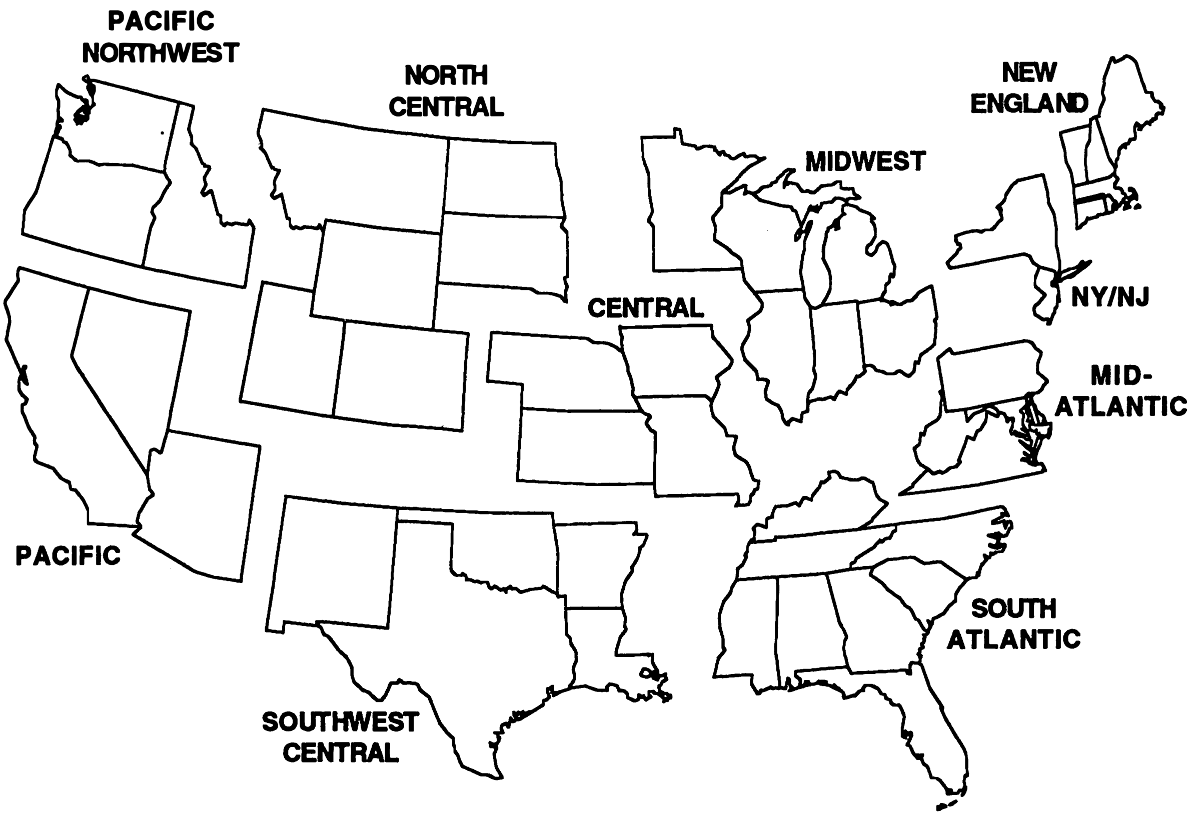


Figure 2-1. NPC Capacity Study Regions.

TABLE 2-1

EXISTING SYSTEM AT A GLANCE—1991
(Billion Cubic Feet per Day)

	Pipeline Capacity			Storage Withdrawal Capability	Total
	In	Out	Net		
Consuming Regions					
New England	2.3	0.0	2.3	0.0	2.3
New York/New Jersey	8.9	2.1	6.8	1.0	7.8
Mid-Atlantic	9.2	9.2	0.0	11.3	11.3
South Atlantic	19.5	14.5	5.0	3.4	8.4
Midwest	21.6	7.1	14.5	17.8	37.3
Central	11.8	7.8	4.0	2.7	6.7
Pacific Northwest	2.7	1.5	1.2	0.5	1.7
South Pacific	5.6	0.0	5.6	5.1	10.7
Supply Regions					
SW Central	2.3	34.3	(32.0)	10.1	(21.9)
North Central	2.8	3.8	(1.0)	1.9	0.9

the U.S. The remaining eight regions are net consuming regions. Although not shown separately in Table 2-1, 5.4 BCF/D of capacity is available to deliver Canadian imports; 4.2 BCF/D of this capacity is delivered directly to the eight primary consuming regions. Finally, a little under 0.3 BCF/D is available in New England from the Everett, Massachusetts, LNG import terminal (this amount is included in the 2.3 BCF/D of pipeline capacity into the region shown in Table 2-1).

It is also interesting to note that the Mid-Atlantic region shows a balance of pipeline capacity on a peak-day basis. This is due primarily to the extensive storage fields located in the region. (The Mid-Atlantic region also accounts for a significant portion of Appalachian production.) Mid-Atlantic storage provides service for a significant portion of the Eastern Seaboard regions; storage gas is transported to both the New York/New Jersey and New England regions and delivered by backhaul[5] to the South Atlantic region. On an annual basis, the Mid-Atlantic region receives the vast majority of its supplies from other regions.

Estimated U.S. Peak-Day and Annual Delivery Capability

An estimate of U.S. capability to deliver gas was developed using the survey of existing system capability and an analysis of historical peak-day consumption trends. This **peak-day capability** in 1991 is estimated to be the sum of:

- The gas consumed in the major supply regions (Southwest Central and North Central)—estimated at 27.7 BCF/D.
- The capacity leaving the supply regions—estimated at 35.7 BCF/D.
- Net imports into the United States—estimated at 4.2 BCF/D.
- Consuming region production—estimated at 7.0 BCF/D.
- Consuming region storage—estimated at 41.7 BCF/D.
- Consuming region liquefied natural gas and peak shaving[6]—estimated at 3.3 BCF/D.

The result of this analysis equates to an estimated peak-day capability of 119.6 BCF/D for 1991. Although not an exact method of determining capability, it does provide a consistent representative approximation.

The NPC has found this methodology useful in discussing aggregate U.S. capability to deliver natural gas; this methodology does not measure the system's ability to deliver gas to specific locations or to deliver gas within specific regions.

An **annual capability** estimate for 1991 was derived in a similar manner. When estimating annual capability, it was assumed that storage and peak-shaving capacity does not contribute to annual capabilities and that the pipeline capacity was available at a 95 percent annual utilization to account for maintenance and other factors causing downtime. The annual capability estimate is the sum of:

- The gas consumed in the major supply regions (Southwest Central and North Central)—estimated at 7.5 TCF per year.
- The capacity leaving the supply regions—estimated at 12.3 TCF per year.
- Net imports into the United States—estimated at 1.5 TCF per year.
- LNG import capacity (0.1 TCF per year) and regional production (2.6 TCF per year)—estimated at 2.7 TCF per year.

The result of this analysis equates to an estimated annual capacity of 24.0 TCF for 1991.

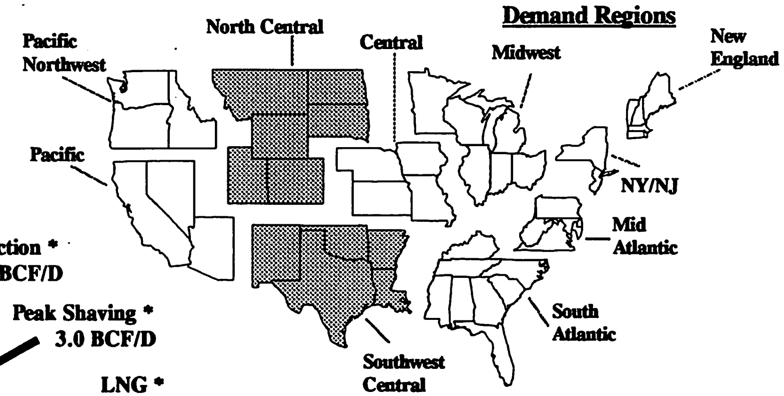
The following diagram, Figure 2-2, supports this analysis of the estimated U.S. peak-day and annual delivery capability.

As a benchmark, similar capability estimates were performed for the year 1988 utilizing the results from the 1989 NPC report entitled *Petroleum Storage & Transportation*.

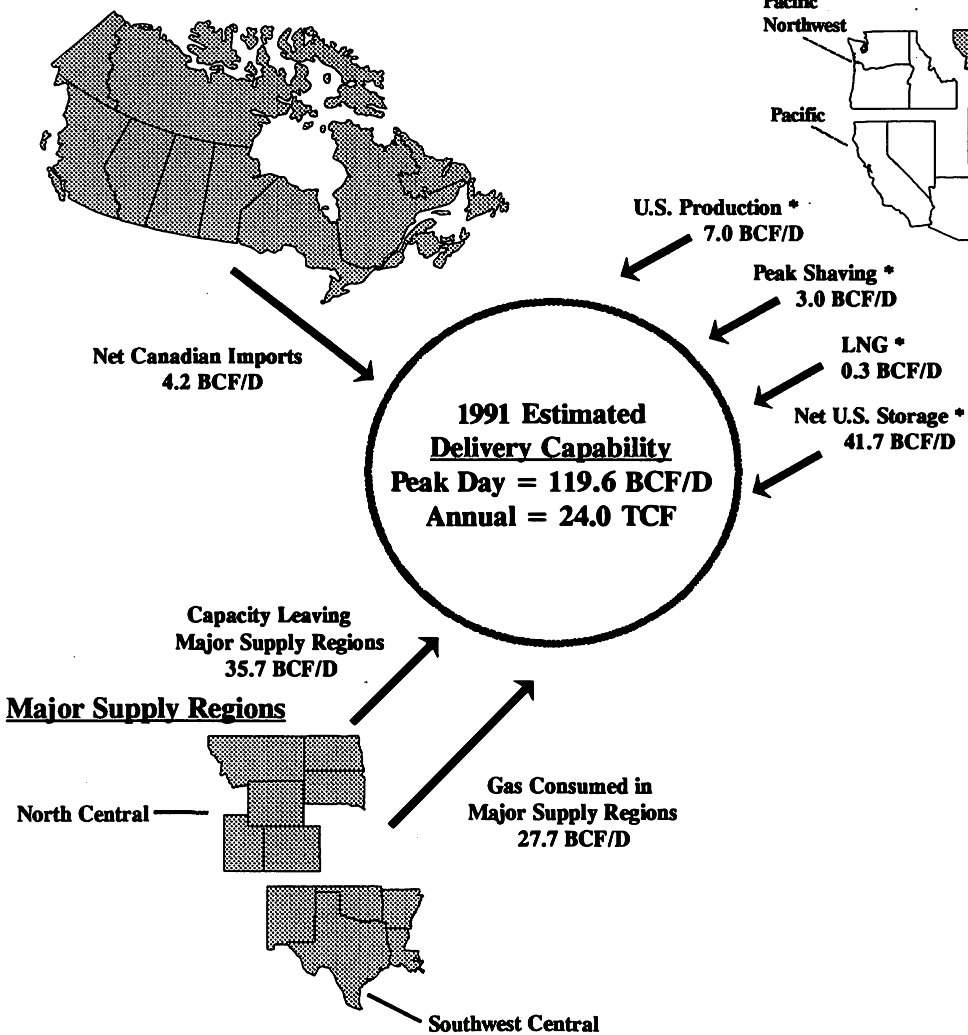
[5] Deliveries by backhaul are effected by delivering other upstream supplies, in this case primarily from the Gulf Coast, to South Atlantic customers, which are later replaced further downstream with withdrawals from storage.

[6] Based on historical usage patterns, only about 3 BCF/D of peak-shaving capacity is used to meet peak-day demands. However, recent estimates of peak-shaving capacity total nearly 13 BCF/D. For the most part, peak-shaving facilities are used to meet peak-hour demands during extreme design cold weather conditions and to provide a back-up supply during stressful conditions.

Figure 2-2. 1991 Estimated U.S. Capability to Deliver Natural Gas (Based on Reference Case 1).



*Note: Excludes deliveries from SW Central and N. Central Regions



U. S. Delivery Capability Calculation

	Peak Day (BCF/D)	Annual (TCF)
Leaving/Consumed in Major Supply Regions		
Capacity Leaving SW Central Region (1)	33.0	11.4
Capacity Leaving N. Central Region (1)	2.7	0.9
Gas Consumed in SW Central Region	23.3	6.6
Gas Consumed in N. Central Region	4.4	0.9
Net SW Central / N. Central Capacity	63.4	19.8
Canadian Imports		
Capacity from All of Canada (1)	6.4	2.2
Less Canadian import to N. Central	(1.2)	(0.4)
Less Re-exports to Canada (1)	(1.0)	(0.3)
Net Canadian Imports	4.2	1.5
Demand Region Deliverability		
Total U. S. Storage Withdrawal	53.7	0.0
Less SW Central and N. Central	(12.0)	0.0
Net U. S. Storage (2)	41.7	0.0
U. S. Production (3)	7.0	2.6
Peak Shaving (3)	3.0	0.0
LNG (3)	0.3	0.1
Grand Total	**119.6**	**24.0**

(1) Annual volume assumes peak day capacity at 95% load factor
(2) Assumed no contribution from storage on an annual basis
(3) Less Contributions from SW Central & N. Central

TABLE 2-2

COMPARISON OF ESTIMATED CAPABILITY, 1988 AND 1991

	1988 Estimated Capability (1989 NPC Study)	1991 Estimated Capability	Difference
Peak Day (BCF/D)	114.1	119.6	5.5
Annual (TCF/D)	21.2	24.0	2.8

However, the demand regions and assumptions used in the 1989 NPC study are not the same as those used in this analysis.[7] The 1988 capability summary was performed only as a check to compare a past analysis with future projections. The results of this comparison, shown in Table 2-2, indicate that the 1991 estimated capacities are in line with the 1988 capacity.

Ability of System to Support Growth

The previous analysis estimates U.S. peak-day delivery capability to be 119.6 BCF/D. This compares to the NPC estimate of actual peak-day firm consumption requirements of 102 BCF/D (see Appendix F, page F-3). The estimated U.S. annual delivery capability of 24.0 TCF per year compares to actual 1991 U.S. consumption of 19.2 TCF.

Generally, the additional peak-day delivery capability of nearly 18 BCF/D is primarily attributed to storage and peaking facilities being used at lower than design levels (about 12 BCF/D in supply regions and 6 BCF/D in market regions). This is due to common industry use of these facilities to provide redundancy, reliability, and back-up in case of freeze-offs and other force majeure events. The NPC concludes that additional peak-day growth could be currently supported in supply regions and in selected market regions where there is available capacity. The additional annual delivery capability of nearly 5 TCF is primarily available near supply regions and during off-peak periods in market regions.

As described above, the ability of the system to move additional volumes is also regionally specific. Shifts in market and production patterns since the 1970s have resulted in the continued expansion of the interstate system and the construction of new storage facilities. Extensive interconnects between pipelines have been placed in service as well, providing substantial flexibility and redundancy in the interstate transmission system. Operationally, the current system is designed to address a very different market regionally than was serviced in the early 1970s.

While consumption has declined in most regions of the country, some areas have shown substantial increases. These include the Northeast states, Florida, and California. The needs of the natural gas consumers are increasingly being met by supplies from the North Central (Rocky Mountain) Region and by imported supplies from Canada. Although the Southwest Central area remains both the largest producer and consumer of natural gas, substantial reductions in both aspects of the market have occurred since the peak in the early 1970s. Consumption in this region has declined by 1 TCF (14 percent) since the 1970 level of 7.2 TCF. Production has declined by about 5 TCF and is currently about 80 percent of the 1970 level.

With these changing patterns, some pipeline capacity is underutilized.[8] In 1991:

- Significant additional volumes could be moved into some market areas during off-peak periods. The Midwest has the capacity to receive nearly 20 BCF/D from domestic sources. This capacity was used at a rate of about 66 percent during 1991. The Central region with a capacity of 12 BCF/D was utilized at a rate of about 40 percent during this period.
- The Southwest region with an export capacity of 34 BCF/D and an average utiliza-

[7] For this reason, a capacity diagram and detailed discussion of the 1988 year is not provided.

[8] See Average Day 1991 model results, Appendix F.

tion rate of 66 percent had the greatest capability to export gas to other regions.

During 1991, the capability of the system to move additional volumes of natural gas into the West was limited with effectively full utilization of the pipeline capacity on a year-round basis into the Southern Pacific region and 84 percent utilization into the Northwest. However, two new projects—Kern River and Mojave—increased pipeline capacity into California in early 1992 by 1.1 BCF/D. A third project, sponsored by Pacific Gas Transmission Company, is scheduled to add over 0.8 BCF/D of additional pipeline capacity from Canada in late 1993. The potential need for new facility construction is discussed in the next section.

Finally, it is important to note that new regulatory policies may create a nationwide secondary capacity market by late 1993. The FERC Order 636 provides that interstate pipelines offer capacity release programs. These programs will allow those who have firm contractual capacity rights to release those rights to others. These programs offer the potential to increase pipeline utilization by creating a more efficient market for pipeline capacity and provide the market with a flexible tool supporting market expansion.

Based on this analysis and discussion, the NPC believes the U.S. transmission and storage system is currently well-positioned to support a growing U.S. natural gas industry. To the extent that the existing system needs to adapt to changing supply patterns and specific new markets, the industry will need to construct the facilities necessary to serve customer needs on an economic, efficient, and reliable basis.

There Will Be a Continuing Need for the Construction of New Facilities to Adapt to Changing Supply and Market Patterns; the Estimated Cost of This Construction Is In Line With Past Experience and Should Not Be a Major Constraint to Future Industry Growth

The market for natural gas is projected to grow substantially over the next 20 years. Under the cases analyzed for this study, natural gas consumption in 2010 will range from 21 to 24 TCF, an increase of 8 to 26 percent from the 1991 level of 19.2 TCF. New transmission and storage facilities will be required to support this growing market.

Critical aspects of this growth relate to the location of the expanding market areas and supply sources and the type of service required by the consumers. These factors influence the balance between additional pipeline capacity, development of underground storage, and peak-shaving facilities. The principal requirement of the transmission system is that it be capable of reliably meeting the peak-day demand of its customers who have contracts for firm service. To meet this requirement, facilities developed by the industry are a combination of transmission lines to bring the gas to the market areas and of storage closer to market areas to meet surges in demand.

Using Reference Cases 1 and 2, the analysis presented in this chapter:

- Evaluates the expansion of the transmission and storage capacity needed to meet the demand and supply particular to the assumptions of these cases
- Estimates the capital costs associated with these expansions.

The key results of this capacity analysis are:

- Natural gas consumption on the peak day is expected to increase significantly—ranging from 8 to 23 percent over 1991 levels by 2010. The growth is due to an increase in firm load requirements including growth in the electric generation (combined-cycle) and cogeneration markets for natural gas.
- A significant shift in regional supply and consumption patterns will affect future transmission and load balancing requirements by 2010. This is due to a projected 23 percent decline in production from the Southwest Central region and the increasing supplies from relatively new supply sources such as from the North Central region and Canada.
- The industry will require additional transmission and storage capabilities for use in the post-2000 period. Storage capabilities need to expand by approximately 1.1 BCF/D. The capability to move gas from the North Central Region, and from

Canada to neighboring regions will more than double by 2010. Additional expansions will be required in the Northeast and into the California region.

- Aggregate throughput capacity under Reference Case 1 is projected to increase 30 percent by 2010, growing from 24 TCF per year in 1991 to approximately 30 TCF in 2010.
- Between 1992 and 2010, investments of between $6 billion and $16 billion dollars will be necessary to expand existing pipeline and storage facilities to satisfy market requirements in Reference Case 2 and Reference Case 1, respectively.
- The $6 to $16 billion of estimated total capacity expansion would average approximately $0.3 to $0.9 billion if expended evenly over the study time frame. The Transmission and Storage Task Group conducted a survey of pipeline companies to estimate future maintenance and replacement expenditures, which resulted in an estimate of $1.7 billion per year. Therefore, the total levelized industry expenditures are estimated to be $2.0 to $2.6 billion per year. This levelized estimate approximates the average total industry expenditures from 1970 to 1990 of $2.4 billion per year (1991$) and should not be a major constraint to future industry growth.

The focus of the capacity analysis is on the ability of the interstate network to move gas on an interregional (i.e., long-haul) basis and to accommodate seasonal load variations through the use of storage facilities. Because the supply and demand data were aggregated on a regional basis, this analysis does not identify specific intraregional bottlenecks, nor does it evaluate specific pipeline expansion projects.

The next section briefly describes the methodology used to assess future capacity requirements. Subsequent sections present future trends in peak-day loads, future capacity, and investment requirements in additional storage and transmission facilities.

Analytical Approach to Assessing Capacity Expansion Requirements

The analysis consisted of three steps:

1. Estimate supply and consumption levels through 2010 for the peak and average January day based on Reference Cases 1 and 2.
2. Assess the adequacy of the inter-regional system to satisfy the future load requirements.
3. Identify future capacity expansion requirements and the associated capital costs of those expansions.

The task group approached the study of capacity expansions by examining the peak-day requirements implicit in the Reference Case annual projections. The reasons for addressing the capacity requirements at this level were twofold. First, as noted earlier, the transmission and storage system is designed to meet the firm peak-day requirements of customers. Second, this approach allowed the evaluation of the seasonal aspects of the demand and the role of storage in meeting the seasonal demand variation. The role of storage in meeting demand is not normally considered in annual projections of market equilibrium.

The focus of the study was on January-average-day and peak-day market requirements under "normal" weather conditions. January-average-day and peak-day requirements were analyzed at five-year intervals to understand the timing of the facility expansions.

Estimates of existing capacity (described in the previous section) as well as supply and demand estimates for the peak January day were developed from the annual projections in Reference Cases 1 and 2. A simple network model was used to examine the feasibility of satisfying the market requirements. Pipeline and/or storage capacity was added as necessary. If demand within a region exceeded transmission capacity to the region (given the slate of supplies available), then additional capacity was added to move existing supplies. If additional supplies were needed to satisfy the market, storage and/or peak-shaving capabilities were added as necessary.

The criteria used to add capacity and the profile of daily supply and consumption balances are presented in Appendix D. The key supply and demand assumptions for the peak and average January day are presented in Table 2-3.

TABLE 2-3

SUMMARY OF ASSUMPTIONS USED IN PEAK-DAY ANALYSIS

	Average January Day	Peak Day
Demand		
Residential	100% firm	100% firm
Commercial	100% firm	100% firm
Industrial	Cogeneration is 100% firm	Cogeneration is 100% firm
Electric Utility	Combined-cycle is 100% firm	Minimum firm load; Combined-cycle uses alternative fuel capability
Supply		
Production	Maximum daily productive capability derated by 2.5% in all regions	Maximum daily productive capability derated by 6.5% for Southwest Central, 4.0% for Central, and 2.5% in the remaining regions
Imports	Through 1992, planned import capacities are assumed. Thereafter, the larger of the model flows or in-place capacity.	Same as for January average day
LNG	Through 1992, 840 MMCF/D capacity. 1993 through 2010, 915 MMCF/D capacity	Through 1992, 980 MMCF/D capacity. 1993 through 2010, 1,060 MMCF/D capacity
Underground Storage	1991 deliverability of 23 BCF/D. Capacity is added throughout the forecast horizon as needed.	1991 deliverability of 54 BCF/D. Capacity added on the average January day is available.
Peak Shaving	Not available on average January day	3.0 BCF/D is available from existing facilities throughout forecast horizon

Existing pipeline capacity between regions and regional storage capacities are based on the estimates provided in the previous section.

Based on a study of AGA data, the nation has approximately 12.7 BCF/D of peak-shaving capability located throughout the market regions. Of the 12.7 BCF/D available, historically less than 3 BCF/D is utilized. Peak-shaving facilities are operated primarily by the distributors located within the market regions. A portion of these facilities were developed during periods of greater demand. The recent gas surplus situation of the 1980s and energy conservation action has reduced the reliance on these facilities. Many of the distributors rely on peak-shaving units to handle hourly fluctuations during peak situations, not as a replacement firm gas supply/transport from the interstates. For these reasons, the availability of peak shaving was limited to 3 BCF/D on a peak day and is assumed to have a negligible contribution to the annual capability.

One supply source that is utilized for the day-to-day operation of the nation's pipeline system and is inherent to each pipeline is line pack. Line pack within a pipeline fluctuates constantly to react to demand changes over short periods of time. Any withdrawals from line pack to support market swings must be replenished to maintain system integrity. Typically, a true peak day is preceded by 2 or 3 days of sustained colder than normal weather, which in effect would have depleted any available line pack. Therefore, for purposes of the NPC capacity analysis, line pack is assumed to be zero on the peak day.

The capital costs associated with the additional capacity required through 2010 were also estimated. Pipeline and storage operations are very capital intensive. The investment costs associated with the unplanned capacity additions (both pipeline and storage) are estimated based on recent FERC certificate filings. These were developed using the investment cost assumptions provided in Table 2-4 and further supported in Appendix E. The focus of the detailed capital cost analysis was on Reference Case 1 because it includes a higher load growth and more extensive facilities than Reference Case 2.

Simplifying assumptions were made in this analysis. While the resulting estimates therefore are subject to some uncertainty, the results provide a useful tool to evaluate the ability of the transmission and storage system to meet future requirements.

Future Trends in Peak-Day Loads

In Reference Case 1, total natural gas consumption is expected to reach 22 TCF before the turn of the century, matching the peak 1972 level, and is expected to further increase to over 24 TCF by 2010 (Table 2-5). In contrast, consumption in Reference Case 2 will reach less than 21 TCF by 2010. In both cases, much of the projected growth is in the electric generation and cogeneration uses of natural gas.

Sources of supply are similarly forecast to vary significantly by 2010. Canadian imports are expected to increase substantially over the forecast period. By 2010, production from the North Central Region is expected to double the 1991 level (9 percent of domestic production in 1991) by 2010 and represent 20 percent of domestic production in that year. Annual transmission patterns will shift to accommodate the regional variations in supply and consumption.

The change in annual supply and consumption levels also affects the seasonal load requirements. However, there is not necessarily a one-to-one correspondence. That is, depending on the type of service required, a 10 percent increase in annual consumption may

TABLE 2-4

SUMMARY OF ASSUMPTIONS UNDERLYING CAPITAL EXPENDITURE ESTIMATES

Type of System	Unit Rate
Transmission Investments ($ per MCF/D per mile)	
Mature Pipeline Systems: Expansion of existing U.S. pipelines consisting of multiple loop line systems with compression	$1.40
Immature Pipeline Systems: Expansion of existing U.S. single line systems that have the ability to be incrementally expanded through the addition of compression at existing or new stations prior to requiring loop (ex. Iroquois, Northern Border)	$1.25
Incremental Pipeline Systems: Construction of new U.S. transmission pipelines extending into existing market areas	$1.85
Canadian Transmission Systems: Expansion of the transmission pipelines that are downstream of the major Canadian production areas (ex. Foothills in northern Alberta, Trans-Alaska Gas System, Trans-Alaska Pipeline System)	$2.90
Storage Investment	
Cost per thousand cubic feet of working gas	$4.00
Peak-Shaving Investment	
Cost per thousand cubic feet of deliverability	$400.00

TABLE 2-5

SUMMARY OF ANNUAL CONSUMPTION AND PEAK-DAY REQUIREMENTS NPC REFERENCE CASES—1991 AND 2010

Annual Consumption (Billion Cubic Feet)

Sector	History 1991	Reference Case 1 2010	Reference Case 2 2010
Residential	4,563	4,777	4,534
Commercial	2,763	3,400	3,050
Industrial	7,169	8,649	5,905
Electric Utility	2,821	5,198	4,792
Total End Use	**17,316**	**22,024**	**18,281**
Fuel/Exports	1,974	2,236	2,431
Total	**19,290**	**24,260**	**20,712**

Peak-Day Consumption (Billion Cubic Feet per Day)

Sector	History 1991	Reference Case 1 2010	Reference Case 2 2010
Residential	50.9	59.6	53.4
Commercial	25.3	31.2	28.0
Industrial	13.8	18.3	13.0
Electric Utility	2.5	2.8	2.7
Total End Use	**92.5**	**111.9**	**97.1**
Fuel/Exports	9.6	14.1	13.6
Total	**102.1**	**126.0**	**110.7**

affect the peak day more or less than 10 percent, depending on the characteristics (seasonal variation and type of service, either firm or interruptible) of the incremental load. For example, over the last 20 years, peak-day consumption in the United States has remained relatively constant at the same time that annual consumption has declined from the peak level of 22 TCF in 1972.[9] A significant portion of the decline since 1972 has been in reductions in industrial and electric generation loads that are not weather sensitive.

Average January day natural gas consumption by 2010 in Reference Case 1 is projected to increase 34 percent above 1991 levels. This growth is led by increases in firm load (35 percent versus 29 percent for interruptible load) resulting from expanding regional markets for natural gas (Figure 2-3). This analysis assumes that new electric utility combined-cycle facilities will use natural gas on an average January day and alternative fuel capability on a peak day.

The supply outlook, under Reference Case 1, for the average January day is also expected to change between 1991 and 2010, in terms of composition and regional mix. First, domestic production in 2010 is expected to represent 58 to 61 percent of U.S. supply, a reduction from 1991. Imports, including LNG, are expected to increase significantly by 2010. Although in aggregate, domestic production is not projected to change significantly, this masks the marked shift in regional patterns embedded in the forecast. Both cases include

[9] National Petroleum Council, *Petroleum Storage & Transportation,* Volume III: Natural Gas Transportation, April 1989.

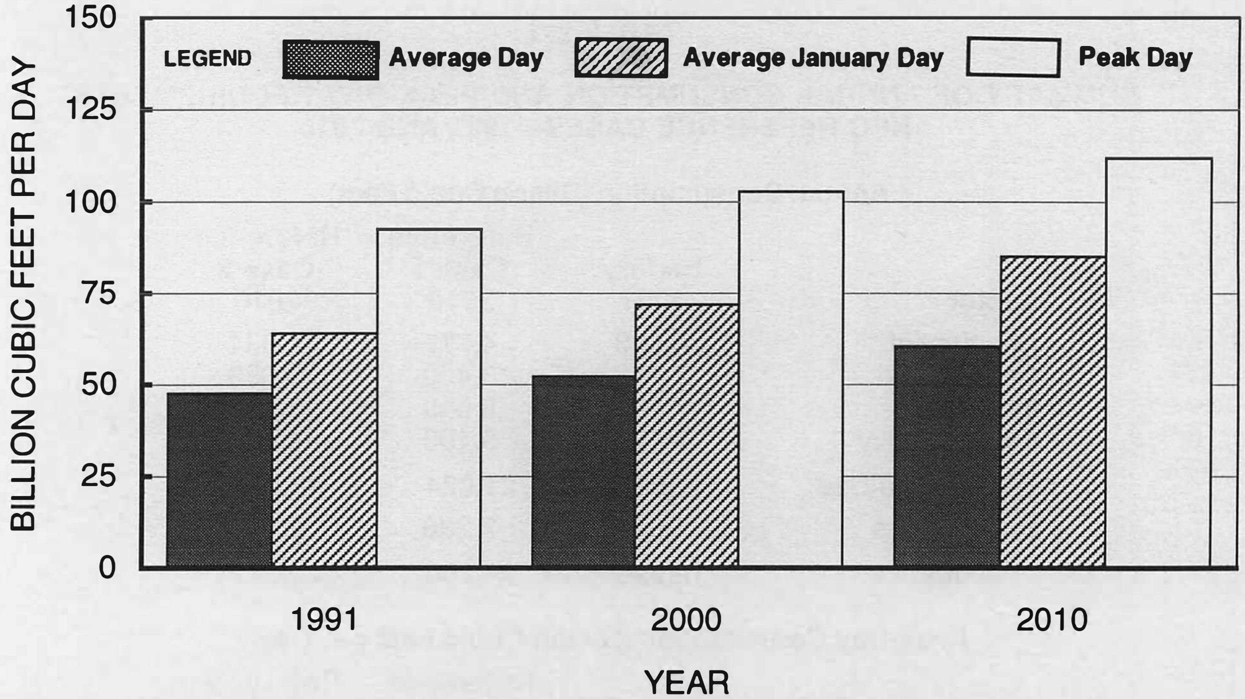


Figure 2-3. End-Use Gas Consumption — 1991, 2000, and 2010 Reference Case 1.

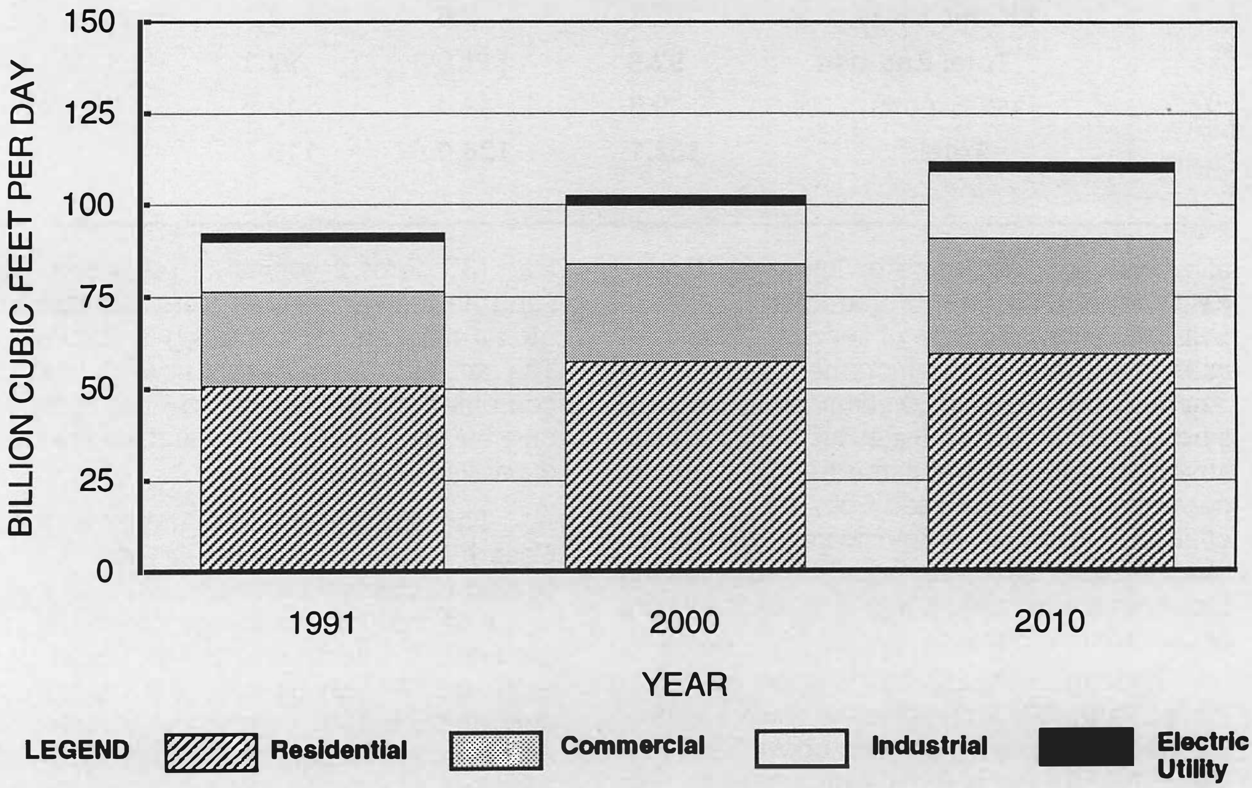


Figure 2-4. Peak-Day Consumption by Sector — 1991, 2000, 2010 Reference Case 1.

a significant increase in production from the North Central Region and a decrease in the Southwest Region.

In Reference Case 1, consumption is projected to increase on the peak day, average January day, and average day (Figure 2-3), and for each sector (Figure 2-4). Assumptions under Case 2 result in less market growth for natural gas, and the peak-day requirements increase only 8 percent above 1991 levels, compared to an increase of 23 percent under Case 1. In this case, the peak-day load increases by 23 percent by 2010, due to growth in firm load requirements across the sectors (Table 2-6). This rate is less than that for the non-peak day, indicating an increased utilization during the off-peak period and a dampening of the seasonal load profile. Approximately 3 BCF of peak-shaving supplies were available for the peak-day-load balancing requirements (Table 2-7).

Future Capacity Requirements

There are two major forces driving the reason for the timing and location of future capacity requirements. Through 2000, market demands are the impetus affecting future capacity requirements. Access to Canadian supply is of primary interest. This appears to be a continuation of the current demand-driven era. Beyond 2000, production from traditional supply regions declines, and replacement production/deliverability develops in other regions. Future capacity requirements are largely supply driven during the 2000 to 2010 period. Based on the NPC Reference Case 1, supply shifts from the Southwest Central to the North Central regions and capacity to disperse supply away from the North Central Region to the neighboring market regions is required. Additional access to imports from Canada continues during this period. During the 1996-2000 period, capacity additions level off, indicating balance between existing supply, increasing annual demand, and the efficient utilization of capacity in place. With the shift in supplies in the 2001-2010 period, capacity additions increase significantly (Table 2-8). On a regional basis, about 300 million cubic feet per day (MMCF/D) and 1,600 MMCF/D of additional capacity are required to transport Canadian supply into the United States, about 1,250 MMCF/D and 3,900 MMCF/D is required to transport gas from the North Central Regions, in the 2001-2005 and 2006-2010 periods, respectively.

A summary of the additional pipeline capacity required, by period, under the Reference Case 1, is provided in Figure 2-5. Utilizing the unit rate investment assumptions presented earlier, the future investment required to support the facility expansions is approximately $16 billion, under the Case 1. Summarized in Table 2-9 is the investment requirement by region. Detailed estimates are included in Appendix E. A similar analysis done for Reference Case 2 yielded an estimate of $6 billion (see Table 2-10).

Future U.S. Capability to Transport Natural Gas

Under NPC Reference Case 1, the natural gas industry will experience an estimated increase in peak-day demand of 25 percent by the year 2010. To meet this demand, substantial new transmission and storage capacity will be required. For comparison purposes the U.S. capability to transport natural gas in 2010 was estimated utilizing the methodology presented for 1991 capability (see Figure 2-6). Appendix F contains this summary for the other years analyzed.

The results from Case 1 and the Transmission and Storage Task Group peak-day analysis were used to determine the projected peak-day and annual capabilities. The results presented in Table 2-11 relate specifically to the volumes and regional distribution of supply and consumption contained in Reference Case 1. Other cases may provide different capacity results.

A detailed illustration of the results are presented in Figure 2-7, for the peak day and Figure 2-8, for the annual results. The graphs identify the major components that make up the capability (top graph) and puts each component as a percent of capability to represent changes of each with respect to the other years (bottom graph). The major components that are used to estimate capability are: (1) the gas consumed in the major supply regions (Southwest Central and Central Regions); (2) the capacity leaving the supply regions; (3) net imports into the United States; and (4) the peak-day storage, LNG, regional production, and peak-shaving deliverability identified for the

TABLE 2-6

**SUMMARY OF REGIONAL PEAK-DAY REQUIREMENTS IN 1991 AND 2010
FOR THE NPC REFERENCE CASES
(Billion Cubic Feet per Day)**

Region	1991	2000	% Change from 1991	2010	% Change from 1991
		Reference Case 1			
New England	2,891	3,171	10%	3,616	25%
New York/ New Jersey	8,012	9,007	12%	9,850	9%
Mid-Atlantic	7,989	9,180	15%	10,110	27%
South Atlantic	9,174	10,925	19%	12,192	33%
Midwest	28,480	33,821	19%	35,555	28%
Southwest Central	23,325	25,604	10%	25,999	11%
Central	6,470	6,789	5%	7,199	11%
North Central	4,428	5,263	19%	6,156	39%
Pacific	9,238	10,457	13%	11,652	26%
Northwest	2,065	2,345	14%	2,697	31%
Total	**102,078**	**116,567**	**14%**	**126,030**	**23%**
		Reference Case 2			
New England	2,891	3,112	7%	3,415	18%
New York/ New Jersey	8,012	8,765	9%	9,238	15%
Mid-Atlantic	7,989	8,655	8%	9,063	13%
South Atlantic	9,174	9,870	8%	10,130	10%
Midwest	28,480	31,690	11%	31,978	12%
Southwest Central	23,325	22,668	– 3%	23,183	– 1%
Central	6,470	6,240	– 4%	6,254	– 3%
North Central	4,428	4,759	7%	5,157	16%
Pacific	9,238	9,703	5%	10,238	11%
Northwest	2,065	1,944	– 6%	2,031	– 2%
Total	**102,078**	**107,609**	**5%**	**110,681**	**8%**

remaining demand regions (excluding the Southwest Central and Central Regions).

Figures 2-7 and 2-8 indicate that the capability growth identified above is primarily accomplished through greater reliance on Canadian imports for both the peak-day and annual capabilities. The import growth is the result of the planned capacity additions of approximately 1.3 BCF/D in 1992 plus projected future imports totaling 3.8 BCF/D estimated to be required by 2010. As imports increase, the capacity leaving the major supply regions (Southwest Central and Central Regions) stay relatively constant. On a percentage basis, imports increase in market share from 6 percent in 1991 to 10 percent by 2010.

Capability Comparison to Projected Demand

The estimated peak-day demand for the referenced years are lower than the projected capacity estimates summarized in Table 2-12.

This analysis indicates that there will be additional peak-day capability in excess of firm peak-day requirements throughout the forecast horizon. In the near term, this additional capability is principally the capability to supply ad-

TABLE 2-7

SUMMARY OF ANNUAL AND PEAK-DAY SUPPLY IN 1991 AND 2010 NPC REFERENCE CASES

Annual Supply (Billion Cubic Feet)

Source	Estimated 1991	Reference Case 1 2010	Reference Case 2 2010
Production	17,416	20,485	17,289
Imports	1,659	3,273	2,750
LNG	191	480	597
Underground Storage		NA	NA
Peak Shaving	NA	NA	NA
Total	**19,265**	**24,348**	**20,683**

Available Peak-Day Supply (Billion Cubic Feet per Day)

Source	Estimated 1991	Reference Case 1 2010	Reference Case 2 2010
Production	55.6	56.0	47.7
Imports	6.8	11.9	11.1
LNG	1.0	1.1	1.1
Underground Storage	53.7	54.5	53.7
Peak Shaving	3.0	3.0	3.0
Total	**120.0**	**126.4**	**116.5**

ditional gas from storage in the producing regions. The character of the additional capability changes over time. By 2010, the additional capability is anticipated to be principally underutilized pipeline capacity from the Gulf Coast region, where supply sources are anticipated to decline.

As the pipeline and storage industry develops to meet the changing conditions, additional deliverability to use this underutilized pipeline capacity could be obtained in several ways. These include additional deliverability:

- From supply sources, such as additional drilling programs.
- From storage programs, such as horizontal drilling into existing fields, or the development of salt dome storage. Several salt dome storage fields are being developed to be placed in service over the next few years.

If necessary, these options could be developed to utilize the additional capability in the later years of the forecast.

Discussion of Aggregate Capital Expenditures

In order to support the projected natural gas supply and demand scenarios of the NPC Reference Cases, the NPC estimates that the industry will require a range of expenditures between $6 billion in Reference Case 2 and $16 billion in Reference Case 1 for major capacity expansions, including storage and peaking facilities. The expenditures would range between $0.3 and $0.9 billion per year if expended evenly over the 1992-2010 period. In order to estimate the expenditures required for annual additions to pipeline facilities for continuing operations, excluding major facility expansions, the NPC conducted a survey of 27 interstate pipelines representing over 190,000

TABLE 2-8

PIPELINE CAPACITY REQUIREMENTS THROUGH 2010
REFERENCE CASE 1
(Million Cubic Feet Per Day)

		Base	Incremental Planned Additions	Incremental Forecasted Additions			
From	**To**	**1991**	**1992**	**1995**	**1996-2000**	**2001-2005**	**2006-2010**
NY/NJ	New England	2,001	343	0	0	267	181
NY/NJ	Mid-Atlantic	58	125	0	0	0	0
Mid-Atlantic	NY/NJ	8,148	393	0	0	761	0
Mid-Atlantic	South Atlantic	24	0	0	0	0	0
Mid-Atlantic	Midwest	995	0	0	0	0	0
South Atlantic	Mid-Atlantic	4,601	0	0	0	0	0
South Atlantic	Midwest	9,905	112	0	0	0	0
South Atlantic	Southwest Central	34	0	0	0	0	0
Midwest	Mid-Atlantic	4,501	160	0	0	0	0
Midwest	Central	1,528	313	0	0	0	0
Southwest Central	South Atlantic	19,466	100	0	0	0	0
Southwest Central	Central	9,192	0	0	0	0	0
Southwest Central	North Central	984	0	0	0	0	0
Southwest Central	South Pacific	4,319	746	0	0	0	0
Central	Midwest	7,252	21	0	0	0	0
Central	Southwest Central	160	0	0	0	0	0
Central	North Central	360	0	0	0	0	0
North Central	Midwest	1,363	313	0	0	464	1,452
North Central	Southwest Central	1,084	0	0	0	300	940
North Central	Central	1,040	0	0	0	288	901
North Central	South Pacific	0	700	0	0	194	607
North Central	Pacific Northwest	324	0	0	0	0	0
Pacific Northwest	North Central	259	0	0	0	0	0
Pacific Northwest	South Pacific	1,258	0	0	0	348	912
Canada	New England	32	0	0	0	0	0
Canada	NY/NJ	743	598	0	0	0	776
Canada	Midwest	2,085	418	64	0	115	137
Canada	North Central	1,225	255	300	698	0	401
Canada	Pacific Northwest	2,372	0	654	131	170	312

TABLE 2-9

PROJECTED INVESTMENT REQUIREMENTS
NPC REFERENCE CASE 1
(Millions of 1991 Dollars)

Transmission Route		Planned Investment	Projected Incremental Investment				
From	To	1992	1993-1995	1996-2000	2001-2005	2006-2010	TOTAL
Canada	NY/NJ	$310	$0	$0	$0	$309	$309
NY/NJ	New England	$257	$0	$0	$64	$43	$107
Mid-Atlantic	NY/NJ	$87	$0	$0	$303	$0	$303
Canada	Midwest	$219	$64	$0	$114	$136	$314
Canada	North Central	$46	$100	$233	$0	$134	$467
North Central	Midwest	$56	$0	$0	$804	$2,364	$3,168
	Southwest Central	$0	$0	$0	$429	$1,344	$1,772
	Central	$0	$0	$0	$286	$894	$1,180
	Pacific	$853	$0	$0	$144	$451	$596
Canada	Pacific Northwest	$0	$260	$52	$68	$124	$504
Pacific Northwest	Pacific	$0	$0	$0	$442	$1,158	$1,600
OTHER		$1,191	—	—	—	—	—
Total Trans. Investment		$3,019	$424	$285	$2,653	$6,957	$10,319
U.S. Storage Investment		NA	$0	$0	$0	$2,201	$2,201
TOTAL U.S. INVESTMENT		$3,019	$424	$285	$2,653	$9,158	$12,520
GRAND TOTAL							**$15,539**

TABLE 2-10

PROJECTED INVESTMENT REQUIREMENTS
NPC REFERENCE CASE 2
(Millions of 1991 Dollars)

Transmission Route		Planned Investment	Projected Incremental Investment				
From	To	1992	1993-1995	1996-2000	2001-2005	2006-2010	TOTAL
Canada	NY/NJ	$310	$0	$0	$0	$0	$0
NY/NJ	New England	$257	$0	$0	$40	$19	$59
Mid-Atlantic	NY/NJ	$87	$0	$0	$91	$0	$91
Canada	Midwest	$219	$65	$0	$0	$109	$174
Canada	North Central	$46	$100	$233	$0	$100	$433
North Central	Midwest	$56	$0	$0	$0	$742	$742
	Southwest Central	$0	$0	$0	$0	$422	$422
	Central	$0	$0	$0	$0	$281	$281
	Pacific	$853	$0	$0	$0	$142	$142
Canada	Pacific Northwest	$0	$290	$0	$0	$0	$290
Pacific Northwest	Pacific	$0	$0	$0	$0	$436	$436
OTHER		$1,191	—	—	—	—	—
Total Trans. Investment		$3,019	$455	$233	$131	$2,251	$3,070
U.S. Storage Investment		NA	$0	$0	$0	$0	$0
TOTAL U.S. INVESTMENT		$3,019	$455	$233	$131	$2,251	$3,070
GRAND TOTAL							**$6,089**

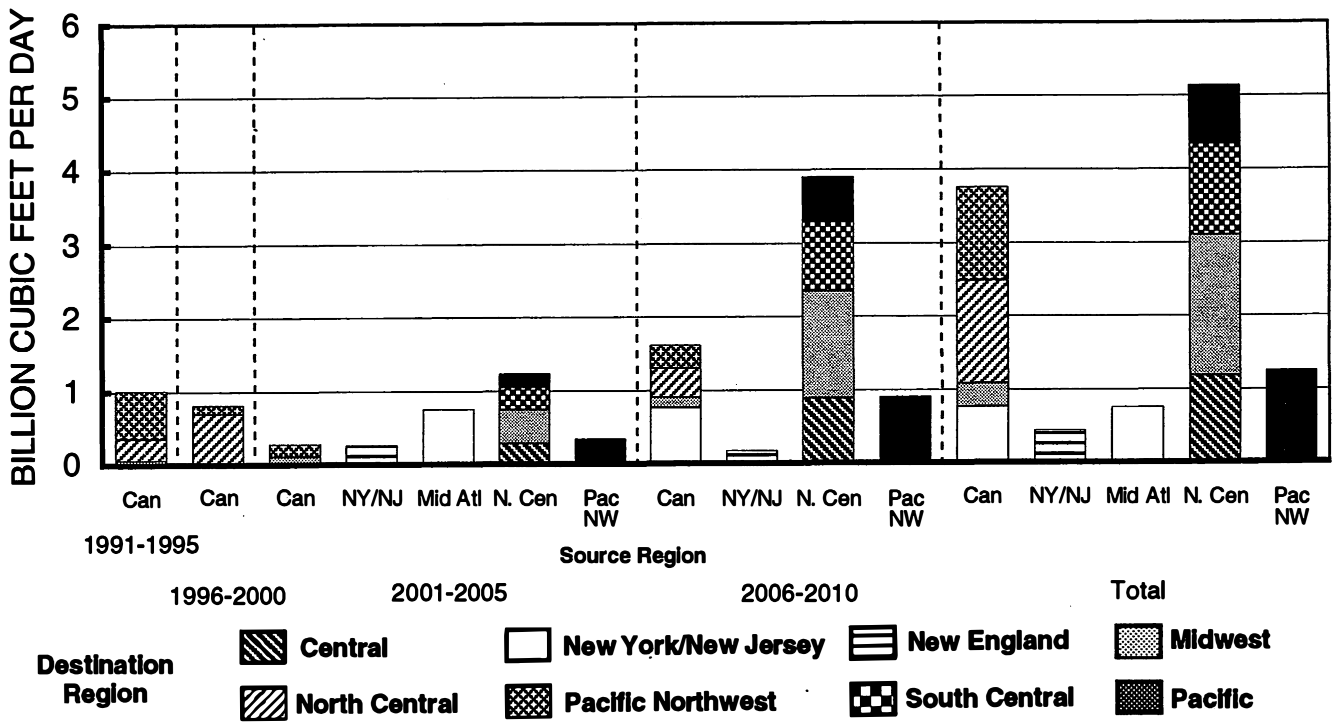


Figure 2-5. Projected U.S. Capacity Additions — Reference Case 1 Additional Peak-Day Pipeline Capacity Requirements.

miles of transmission pipeline. The survey responses were adjusted to reflect total interstate and intrastate pipeline facilities and resulted in an estimated industry expenditure of $1.7 billion annually. Therefore, the total estimated transmission industry expenditures per year for facility additions would range between $2.0 billion in Reference Case 2 and $2.6 billion in Reference Case 1 (1991$).

These estimates were compared to historical expenditures to determine if the level of expenditures would constitute a major constraint to a growing U.S. natural gas market. Pursuant to American Gas Association's *Gas Facts*, construction expenditures for transmission and underground storage facilities have averaged $2.4 billion (1991$) per year from 1971 to 1990. The above estimated range of expenditures for the period of the NPC study approximates this historical average, and therefore, should not be a major constraint to a growing market. Background on the survey and historical expenditures is contained in Appendix E.

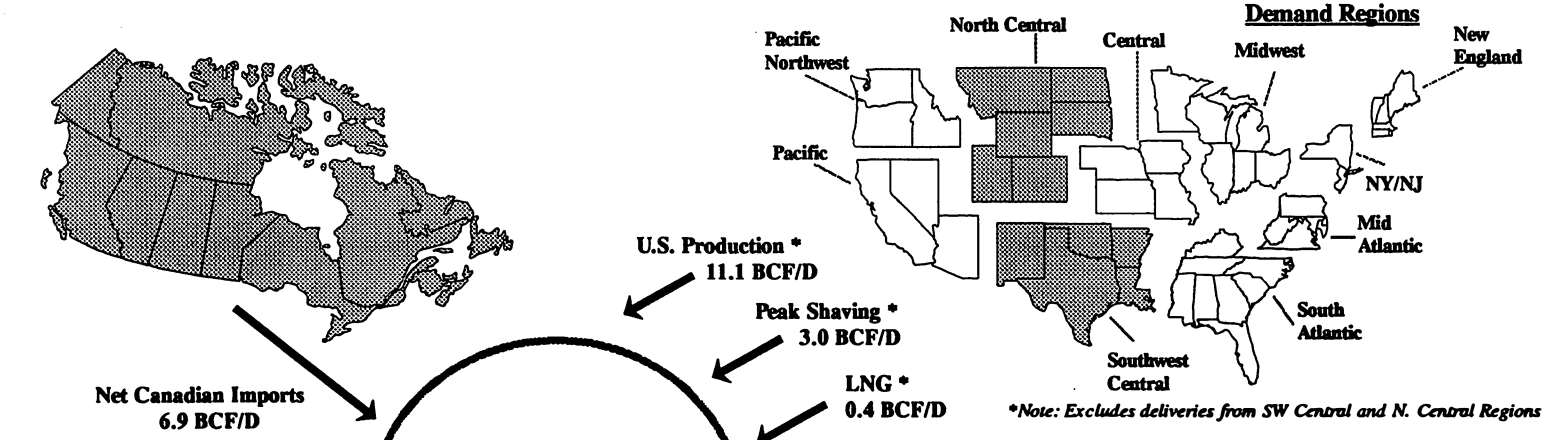
Summary

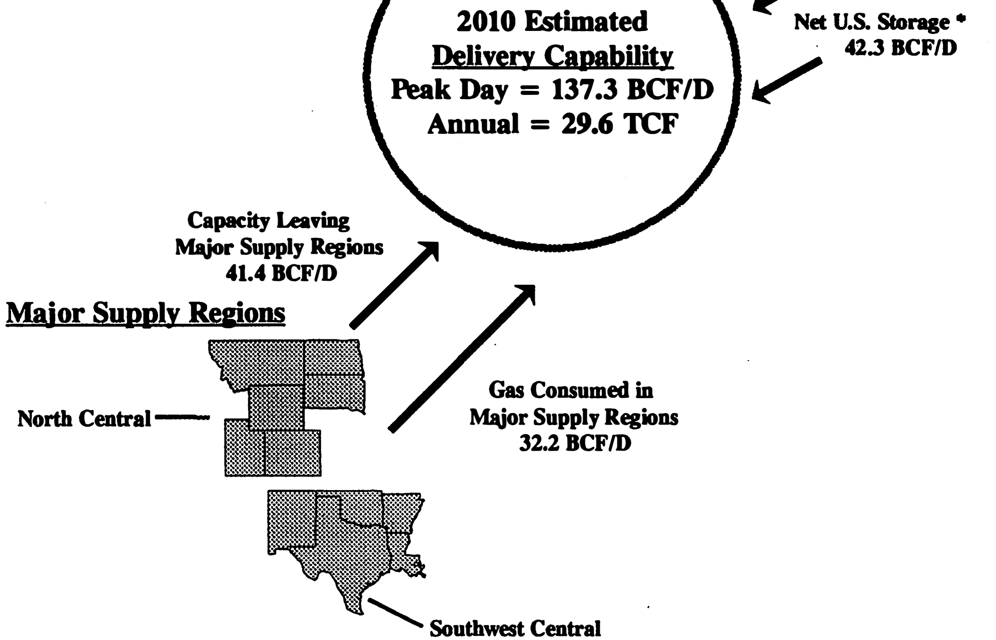
The transmission and storage industry will continue to expand and develop facilities as required to meet customer needs. The estimated capital expenditures associated with new facility construction and maintenance of the existing system are in line with past experience and should not be a major constraint on the increased use of natural gas. This statement is not intended to suggest that these capital expenditure levels are to be taken for granted. In fact, the NPC believes that the industry should take actions to minimize these expenditures, consistent with providing economic, efficient, and reliable service. Discussion of this issue is included in Chapter Five.

The Natural Gas Transmission and Storage System Has—And Continues to Improve—The Ability to Provide Economic, Efficient, and Reliable Service Responsive to Customer Needs

Continued improvement of the transmission and storage system's ability to provide economic, efficient, and reliable service depends on a number of factors. Four areas important to the industry's growth are new capacity additions, investment in improved

Figure 2-6. 2010 Estimated U.S. Capability to Deliver Natural Gas (Based on Reference Case 1).





U. S. Delivery Capability Calculation

	Peak Day (BCF/D)	Annual (TCF)
Leaving/Consumed in Major Supply Regions		
Capacity Leaving SW Central Region (1)	33.8	11.7
Capacity Leaving N. Central Region (1)	7.6	2.6
Gas Consumed in SW Central Region	26.0	7.4
Gas Consumed in N. Central Region	6.2	1.2
Net SW Central / N. Central Capacity	73.6	22.9
Canadian Imports		
Capacity from All of Canada (1)	11.5	4.0
Less Canadian import to N. Central	(2.9)	(1.0)
Less Re-exports to Canada (1)	(1.7)	(0.6)
Net Canadian Imports	6.9	2.4
Demand Region Deliverability		
Total U. S. Storage Withdrawal	54.5	0.0
Less SW Central and N. Central	(12.2)	0.0
Net U. S. Storage (2)	42.3	0.0
U. S. Production (3)	11.1	4.2
Peak Shaving (3)	3.0	0.0
LNG (3)	0.4	0.1
Grand Total	**137.3**	**29.6**

(1) Annual volume assumes peak day capacity at 95% load factor
(2) Assumed no contribution from storage on an annual basis
(3) Less Contributions from SW Central & N. Central

TABLE 2-11

ESTIMATED U.S. CAPABILITY TO TRANSPORT NATURAL GAS*

Year	Peak-Day (BCF/D)	Annual (TCF/year)
1988†	114.1	21.2
1991	119.6	24.0
1995	126.2	25.7
2000	128.9	26.8
2005	130.9	28.0
2010	137.3	29.6

*Estimated based on NPC Reference Case 1 and the Transmission and Storage Task Group capacity analysis.

†Based on data extracted from the 1989 NPC report, *Petroleum Storage & Transportation.*

technology, environmental compliance, and the continuing transition to a more competitive market environment. Improvements in each of these areas can make a significant contribution to the industry's ability to grow and respond to changing market needs.

Recent Capacity Additions

Significant additional capacity has been recently installed and new projects are planned to meet new customer demands.

Table 2-13 summarizes the interstate pipeline capacity increments identified in the Existing System Study contained in Appendix C. The New England, New York/New Jersey, and South Pacific regions all show substantial increases in pipeline capacity through 1993. The South Pacific region alone is scheduled to receive a 40 percent increase in pipeline capacity, increasing by 2.2 BCF/D by late 1993. The Pacific Northwest is scheduled to receive a 31 percent increase in capacity by 1993. The New England and New York/New Jersey regions are also expected to see healthy increases totaling over 1.1 BCF/D by 1993. Altogether, these capacity additions are expected to cost nearly $5 billion to construct.

The Existing System Study, described earlier, characterizes the pipeline and storage capacity as it exists today and projects in an advance stage of construction or planning. But there are a number of projects—recently approved by the FERC, or pending FERC approval—which provide significant new capacity. These are projects that were approved after the Existing System Study was finalized, or that have been recently filed with the FERC for approval (see Table 2-14).

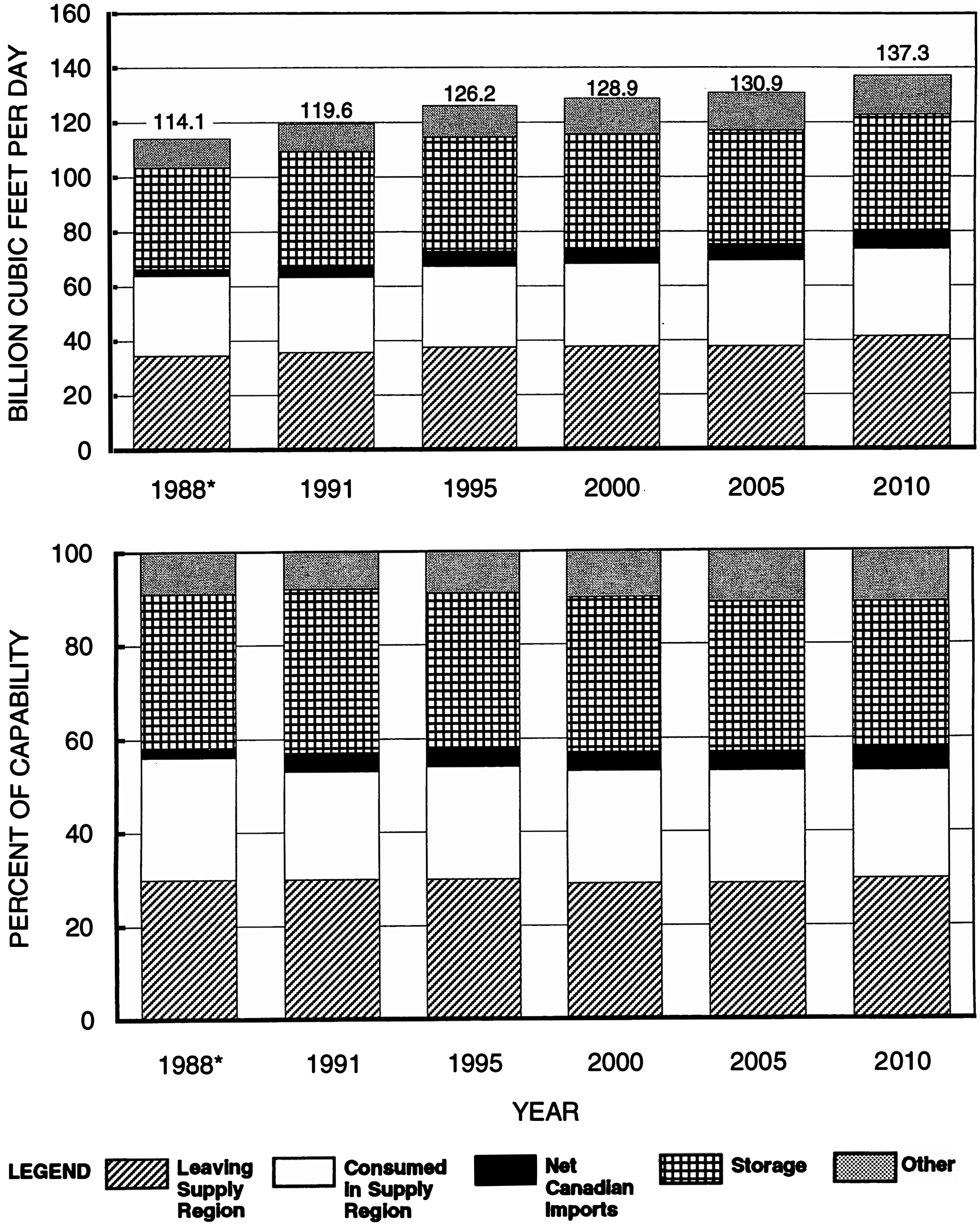
If approved and constructed, these projects would provide over 4.5 BCF per day in additional capacity.[10] Of this, nearly 25 percent will be used to export gas to Mexico. The New York/New Jersey region will also see a significant increase in supply, principally from Canada.

There are also a number of storage projects either recently approved or announced. Altogether, these projects, if ultimately built, would add an additional 99 BCF in winter season supplies and over 2.6 BCF in peak-day deliverability. Regions gaining new storage deliverability include the Midwest (600 MMCF/D), the South Atlantic (1,220 MMCF/D), and the Southwest Central (700 MMCF/D).

Investment In and Use of Technology

The existing pipeline and storage network represents a more than $50 billion investment in facilities to meet current demands. This includes investment in high strength steel pipelines, compression facilities, sophisticated electronic measurement, command and control facilities (e.g., computers), and use of constantly improving construction, testing, and

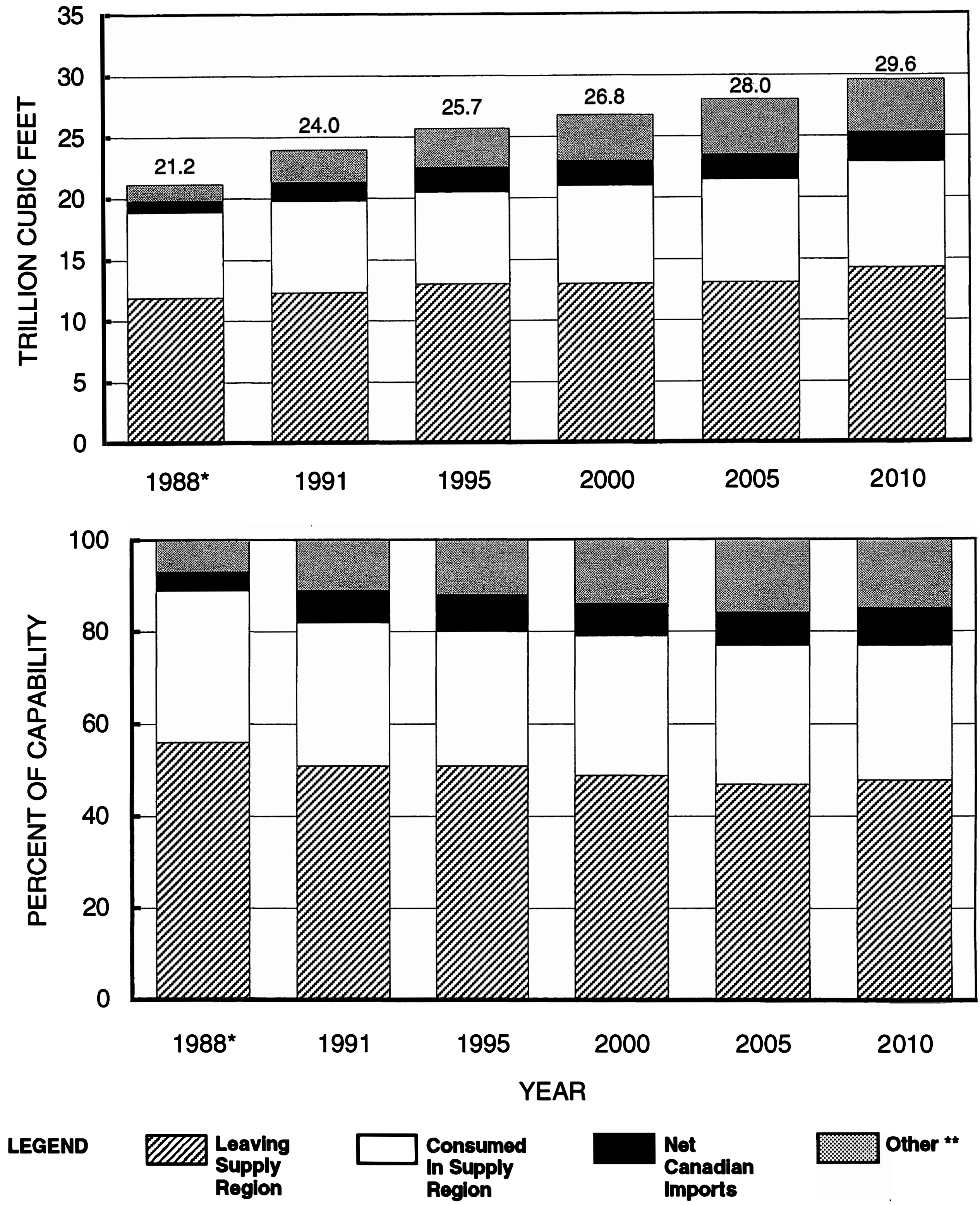
[10] Seven of 21 projects are already approved.



* Data extracted from 1989 NPC report on Storage and Transportation, Vol. 5.

** Other includes: LNG, Peak Shaving, and U.S. Production.

**Figure 2-7. Peak-Day Capability Profile 1988-2010
Estimated U.S. Peak-Day Transmission Capability
Reference Case 1.**



* Data extracted from 1989 NPC report on Storage and Transportation, Vol. 5.

** Other includes: LNG, Peak Shaving, and U.S. Production.

Figure 2-8. U.S. Capability Profile 1988-2010
Estimated Annual Transmission Capability
Reference Case 1.

TABLE 2-12

PEAK-DAY AND ANNUAL CAPABILITY COMPARED TO DEMANDS, 1991-2010

Year	Peak-Day Capability (BCF/D)	Projected Firm Peak-Day Demand (BCF/D)
1991	119.6	102.1
1995	126.2	113.7
2000	128.9	118.2
2005	130.9	122.2
2010	137.3	125.5
Year	**Annual Capability (TCF)**	**Projected Annual Demand (TCF)**
1991	24.0	19.2
1995	25.7	20.9
2000	26.8	22.2
2005	28.0	23.5
2010	29.6	23.7

maintenance techniques and technologies. This investment is a tangible sign of the industry's commitment to providing safe, reliable, efficient, and economical service.

From the advent of high strength steel pipelines in the 1930s the industry has invested in the best available materials to construct its pipeline system. Significant innovations have been employed, as they became available, to extend the safe efficient operating life of pipeline facilities. Some of these innovations include use of improved pipe-making techniques, cathodic corrosion protection, exterior pipeline coatings, and improved compressor motors.

The industry also funds research and development activities aimed at technological improvements. The Gas Research Institute, the Pipeline Research Committee of the American Gas Association, as well as various manufacturers and individual companies funded over $22 million in research and development in 1992. Industry funding for the Gas Research Institute program comes from membership fees and a surcharge assessed on all interstate natural gas services. These research activities are closely coordinated among the various industry groups and jointly funded, at times with the participation of various government agencies including the Department of Energy and the Department of Transportation.

Technology also plays a central role in understanding the performance of natural gas transmission and storage facilities. The development of (relatively) inexpensive desktop computers, more sophisticated pipeline flow models, and electronic telemetry (measurement, communication, command, and control equipment) has enhanced the industry's ability to:

- Design the most efficient, cost effective, new pipelines
- Optimize the operating efficiency of existing pipelines
- Monitor and control pipeline operations.

These technologies are available and in use today, replacing manually intensive, rule of thumb techniques more commonly in use as recently as a decade ago. The industry continues to improve and expand the use of these ("real-time") systems to meet the demands of today's more competitive marketplace.

These technologies also provide a solid foundation for improvements in customer communications and the coordination of operations among producers, pipelines, local distribution companies, and their customers. Current efforts are underway to develop the techniques to provide electronic links between pipelines and customers that reduce the administrative requirements of today's fragmented marketplace.

The changes taking place in the interstate pipeline industry today place increasing demands on the natural gas pipeline industry to construct, operate, and coordinate the operation of pipelines and storage facilities in an efficient, economic, and reliable manner. The restructuring of the pipeline industry mandated by the FERC Order 636 will require changes in the industry's physical facilities and operating practices to meet the challenges of completely revamped operating conditions. New technologies in computers and electronic communications will play a crucial role in the transition to an unbundled marketplace.

Environmental Compliance

The construction of interstate pipelines falls under the jurisdiction of the Federal Energy Regulatory Commission, a federal regulatory agency. The FERC must comply with certain environmental statutes, including the National Environmental Policy Act of 1969 (NEPA), the National Historic Preservation Act, the Endangered Species Act, and the Coastal Zone Management Act. As part of its NEPA responsibilities, the FERC is also required to examine the pipelines' compliance with various federal environmental statutes, including the Clean Air Act, the Clean Water Act, and a number of other environmental statutes. The FERC's regulations require pipelines to assist the Commission with its compliance with these statutes by preparing environmental studies and compiling information relevant to the potential environmental impacts of pipeline construction projects.

For projects that require FERC review and authorization prior to construction, the FERC conducts an environmental review to ensure that the location of facilities is appropriate and that construction and operation of facilities takes place in an environmentally acceptable fashion. The FERC also coordinates its environmental

TABLE 2-13

SUMMARY OF NET INTERREGIONAL PIPELINE CAPACITY CHANGES (1992-1994)
(Billion Cubic Feet per Day)

Regions	1991 Capacity	Incremental Capacity 1992	1993	1994	Total	Total Percent Change
MARKET REGIONS						
New England	2,318	343	0	0	343	15
NY/NJ	6,832	523	298	0	821	12
Mid-Atlantic	(7)	(108)	(138)	0	(246)	3,514
South Atlantic	4,950	(12)	(147)	0	(159)	(3)
Midwest	14,523	(91)	(78)	0	(169)	(1)
Central	3,988	292	0	0	292	7
Pacific Northwest	1,179	0	366	0	366	31
Pacific	5,577	1,446	798	0	2,244	40
Total	**39,360**	**2,393**	**1,099**	**0**	**3,492**	**9**
SUPPLY REGIONS						
Southwest Central	(32,083)	(1,446)	0	0	(1,446)	5
North Central	(883)	(758)	(55)	736	(77)	9
Canada	(5,409)	(789)	(1,064)	(736)	(2,589)	48
LNG Imports	(985)	0	0	0	0	0
Mexico	370	0	0	0	0	0
Total	**(38,990)**	**(2,993)**	**(1,119)**	**0**	**(4,112)**	**11**

TABLE 2-14

RECENTLY APPROVED AND PENDING INTERSTATE PIPELINE CONSTRUCTION PROJECTS

Regions	Incremental Capacity			
	1992	1993	1994	1995
To Mexico From:				
Pacific	0	0	350	0
Southwest Central	1,031	0	0	0
To Mid-Atlantic From:				
Midwest	0	111	90	61
To New England From:				
NY/NJ	0	41	35	46
To NY/NJ From:				
Mid-Atlantic	0	66	110	61
Ontario	400	210	0	0
To Ontario From:				
Midwest	0	0	56	118
To Pacific Northwest From:				
British Columbia	0	448	0	0
To South Atlantic From:				
Southwest Central	0	535	322	0
To Pacific From:				
North Central	0	452	0	0
Total	**1,431**	**1,863**	**963**	**286**

review with other federal and state agencies with environmental and project siting responsibilities.

Except for replacement projects,[11] the construction of projects which do not require prior FERC review are subject to standard environmental conditions set forth in FERC's regulations at 18 CFR Section 157.206(d). These regulations require that construction follow accepted environmental practices, and that the pipeline consult with other agencies with environmental responsibilities (e.g., the protection of historic and cultural resources, endangered species, parks, national and state forests, waterways and wetlands) prior to construction.

A significant concern of the industry is the time required to complete environmental review procedures. Although the time required has been significantly reduced in recent years, streamlining environmental review (and generally the FERC permitting process) has become an industry and a FERC priority. In September 1991, the FERC issued Order 555, which would have implemented substantial changes in the environmental review and permitting process. However, the FERC indefinitely postponed the effective date of these changes in response to numerous rehearing requests.

FERC Order 555 contained a number of changes to the FERC environmental review process. First, it contained comprehensive re-

[11] Maintenance and replacement of existing pipeline facilities is exempted from both permitting and environmental review procedural requirements under current FERC regulations (See 18 CFR § 2.55).

quirements for environmental compliance and reporting. These requirements included specific acceptable techniques for compliance in a number of areas, while providing flexibility for pipelines to adopt other acceptable techniques where appropriate. Second, it provided for public notification requirements. Third, it included an administrative process designed to deal with (potentially resolvable) environmental protests and to avoid more burdensome case-specific procedures. Fourth, it required the filing of an environmental report 30 days prior to construction for some projects. Finally, it significantly expanded the class of projects which could be constructed without prior FERC permitting review, subject to compliance with the environmental guidelines.

While Order 555 has not been implemented, the FERC, the industry, and other agencies continue to seek ways to streamline the environmental review process while continuing to ensure that pipeline construction takes place in an environmentally sound manner.

Continuing Transition Towards a More Open and Competitive Market

Traditionally, the interstate natural gas marketplace was characterized by wellhead to burnertip regulation of all aspects of business. But today natural gas markets are based increasingly on competition, and becoming more competitive every day. These changes started with wellhead deregulation begun by the Natural Gas Policy Act of 1978. This was followed by open-access pipeline transportation in 1985, and in 1992 the beginning of industry-wide restructuring of interstate pipeline services. The result of this competition has been a substantial decline in prices across all industry segments. Average wellhead prices declined, in constant 1991 dollars, more than 50 percent between 1984 and 1991. And prices to all customer classes declined as well: residential prices declined 26 percent; commercial prices declined 31 percent; and industrial and electric utility prices declined over 50 percent.[12] This section will discuss these changes in the way the natural gas marketplace operates.

[12] DOE/EIA, *Natural Gas Annual* (1987 and 1990 editions), Table 1; and *Natural Gas Monthly*, April 1992, Table 4.

Wellhead Deregulation

From 1954 until 1978, natural gas wellhead sales were subject to the same regulatory scheme set for interstate pipelines. During this period, most natural gas flowing in interstate commerce was purchased and resold by interstate pipelines. Most consumers had no choice but to buy from those pipelines.

In 1978 the phased decontrol/deregulation of wellhead sales of natural gas was mandated by the Natural Gas Policy Act (NGPA). The NGPA was based on a philosophy that reliance on market forces, where competitive markets were possible, was a better foundation for achieving public interest goals—adequate supplies of natural gas at fair prices—than regulation. This philosophy has now been extended from the wellhead virtually to the burnertip, thanks to a recognition that competition need not stop at the wellhead.

However, the NGPA—coupled with prevailing regulatory and industry practices—had some unintended consequences. While wellhead prices for natural gas increased during the early 1980s, competing prices for oil fell precipitously. The economy also suffered declines during this period. These factors combined to yield significant oversupplies of natural gas. For the first time since 1954, natural gas wellhead prices began to be set by the market, at levels below regulated ceiling prices.

For most of the 1980s, the so-called "gas bubble" lead to a series of regulatory and industry actions attempting to bring natural gas markets into balance. However, the gas bubble continued throughout the 1980s, finally leading to further legislation. In 1989 the Natural Gas Wellhead Decontrol Act was enacted. Subsequently, natural gas wellhead sales under new or renegotiated contracts would no longer be subject to federal regulation. Further, all remaining natural gas wellhead sales are decontrolled effective January 1, 1993.

Open-Access Transportation

In 1985 the FERC issued its seminal Order 436. This order created a voluntary program authorizing "blanket" transportation by interstate pipelines on behalf of any willing shipper. Pipelines operating under this blanket program are required to provide service on an "open-access" basis. In essence, this means that a pipeline may not unduly discriminate among shippers—if it transports for one shipper, it must transport for other "similarly situated" shippers on a non-discriminatory basis.

FERC Order 436 also granted pipelines selective discounting authority. While maximum and minimum cost-based tariff rates were required to be filed with the FERC, the pipelines were allowed to discount their transportation services to meet the market. Pipelines were "at risk" for the revenues lost from discounting; lost revenues could not be recovered in later periods. This authority was also subject to a prohibition of unduly discriminatory discounting.

By 1992, over 90 pipelines were participants in the open-access program. Nearly 80 percent of all natural gas transported in interstate commerce is shipper-owned, as opposed to pipeline sales gas (see Figure 1-10). Between 1984 and 1991, the nationwide average citygate cost of transporting natural gas fell more than 20 percent when measured in constant 1991 dollars.[13] Most of these shipper-owned supplies were transported through short-term interruptible arrangements. This, among other factors, led to complaints that open-access transportation was still not comparable in quality to interstate pipeline sales services. In response, the FERC issued Order 636.

FERC Order 636

In 1992 the FERC issued Order 636. This order applies to all open-access interstate pipelines and mandates nearly complete unbundling of pipeline gas sales from transportation services by the 1993-94 winter heating season.[14] Open-access pipeline companies are required to restructure their contractual relationships with existing firm sales customers. Among other things, Order 636:

- Requires pipelines to offer a new no-notice firm transportation service, equivalent in quality to firm sales service.
- Requires pipelines to offer unbundled (separate) gathering, transportation, storage, and sales services.
- Removes regulatory price controls from pipeline sales and requires that they take place at pipeline receipt points, placing them on the same footing as any other seller of natural gas delivered through open access transportation arrangements.
- Authorizes capacity release programs, allowing the creation of a secondary market for pipeline capacity rights.
- Promotes (but does not mandate) adoption of market hubs and pooling points.
- Requires pipelines to provide electronic bulletin boards to provide shippers with information on available capacity, capacity releases, and other operating information.

The Order 636 program is intended to foster competition where competitive markets exist—for natural gas sales—and to provide a level playing field for all market participants where competition has not yet been shown to exist—for the transportation and storage of natural gas. By separating these two functions, each can be given appropriate regulatory treatment. The FERC-prescribed schedule calls for implementation in time for the new services to be placed in service for the 1993-94 winter heating season. The Order 636 restructuring process should lead to a significantly more open interstate natural gas marketplace.

The Natural Gas Transmission and Storage System Needs to Further Improve Its Ability to Provide Economic, Efficient, and Reliable Service Responsive to Customers' Needs

One result of the increasing market-oriented structure of the industry is the changing roles and functions of the industry participants. Prior to open access, the pipelines played a central role as the primary middleman between producers and local distribution companies. Operationally and contractually, the pipeline had control over the natural gas flowing into, through, and out of its facilities. Under the current restructuring of the industry, the pipeline companies will be operating principally as transporters of natural gas. While pipelines may retain a role in the sale of natural

[13] DOE/EIA, *Natural Gas Annual* (1987 and 1990 editions), Table 1; and *Natural Gas Monthly*, April 1992, Table 4.

[14] In Order 636A, an order on rehearing of Order 636, the FERC provided for the interim continuation of bundled sales services to small customers.

gas as a commodity, that role will occur in a competitive market. Arrangements for the transportation are handled in separate transactions. The system is becoming more flexible but also more complex.

In this environment, the service requirements of the customers of the interstate pipeline industry have changed dramatically. With the evolution toward open access on the transmission system and the increasing use of spot market transactions, the industry has followed with the development of alternative marketing and contracting arrangements. Implementation of Order 636 and the mandated unbundling of nearly all sales, transportation and storage services, are requiring further adjustments in the operation of the transmission and storage industry. Industry services will need to be constantly evaluated to ensure they are:

- ***Economic*** — The competition for new markets and customers is intense. The electric generation market is a prime market for expanded use of natural gas. In many areas, natural gas competes directly with coal for this market.
- ***Efficient*** — The customer should be able to easily obtain the services needed so transaction costs to the customer are minimized.
- ***Reliable*** — The market is increasingly fragmented. New contractual relationships are being formed. The customers require assurance/ demonstration that the system will perform to their expectations during and after transition to the Order 636 market environment.

The profound changes seen in the industry operations over the past few years have resulted in increased fragmentation of the industry and a perceived lack of communication or common purpose among industry segments. This has highlighted concerns about the capability of the industry to attain its expected potential.

In support of the natural gas study, the National Petroleum Council initiated a study to identify impediments faced by the industry as it works to increase demand for natural gas.[15] The approach used focus group discussions with representatives of 15 of the key industry groups that comprise or are served by the industry. Each focus group had three objectives:

- Identify barriers and opportunities for increasing the efficient use of natural gas
- Determine which barriers are myths or misconceptions
- Identify remedial actions that can be undertaken to overcome real obstacles and correct misconceptions.

For the transmission and storage industry, the results of the focus group discussion reflected concern with historical problems, current operational practices, and a pervasive concern regarding regulatory uncertainty and how the restructuring will ultimately impact the service provided by the industry.

Concerns about reliability of the system were frequently mentioned by participants in the focus group discussions. Memories of interruptions during the 1970s, the inability to obtain firm transportation capacity, and uncertainty about the priority of seasonal curtailments of interruptible service continue to trouble segments of the market. Industry marketing programs appear to have failed to eliminate, or effectively counter, memories of the 1970s curtailments and the more recent well freeze-offs and shortages in December 1989. In addition, the industry has not effectively addressed safety fears associated with, for example, older pipeline systems or natural-gas-fired vehicles.

Some focus group participants believe that incremental pricing is a major regulatory obstacle to further capacity expansion projects by placing too much financial risk on the developer. An additional concern is the financial health of interstate pipeline companies. Some participants believe that the interstate pipeline companies are not financially sound, limiting their ability to attract capital to finance expansion projects.

Participants believe that the gas industry and its regulators show little interest or respect for the needs of its customers. Rates and sales programs of pipelines, producers, distributors, and marketing companies are designed to be operationally convenient for the supplying segment rather than designed to address the operational needs of the customers.

---

[15] See Appendix C of Volume V for the summary focus group report: *Understanding Barriers to and Opportunities for Increasing Natural Gas Consumption*, Bentek Energy Research.

Accordingly, customers do not obtain the services that they want and to which they attribute value above the value inherent in the commodity.

Pipeline operating procedures contribute to concerns about pipeline deliverability. Participants suggest that pipeline procedures are constantly changing, are too complicated, and work counter to their needs. In particular, electric utility customers noted that the 24-hour notice required by most pipelines will limit the efficient use of their planned combustion turbines.

Uncertainty is one of the outcomes of the present transitional nature of federal and state regulation. Consumers are unsure of the capabilities of the restructured transportation industry evolving under Order 636. Transportation suppliers are unsure of the rules under which they will operate in the future. No one is confident that the commitments they make will stand the test of time.

Focus group discussions also pointed out inherent inefficiencies in a regulated industry. Fragmentation exists in the natural gas industry today as a result of the adversarial procedures in the regulatory process that positions sectors of the natural gas industry against one another. This typically results in the proliferation of confused and conflicting messages being sent to regulators and customers. In addition, focus group participants feel that regulation diverts the attention of the pipeline industry management from promoting natural gas and meeting the needs of customers. Instead, much attention is focused on meeting the needs of the regulators.

In addition, participants noted that cost-of-service based rates are problematic. First, it encourages rate base building, rewarding pipelines for increasing their capital base and thereby increasing costs. Furthermore, since cost reductions are passed on to customers, regulated pipeline companies are not encouraged to be innovative (or more efficient) to reduce their non-gas costs or to invest in new technologies.

In addition, NPC study participants cited the following concerns:

- Ineffective communication of service quality and service expectations
- Concerns with incentives to provide new services, maximize efficiency, and investment in technology
- Impact of Order 636 implementation on ability to serve new loads especially electric generation
- Difficulties in purchasing and acquiring transportation.

While the specifics vary, it is clear that many industry participants feel that the pipeline industry is not providing or may not be capable of providing the service that they want.

In some cases, the concerns are based on historical problems where the transmission and storage industry has made significant progress in reducing the likelihood of similar problems. A prime example is the persistent concern about the curtailments of service during the late 1970s and difficulties experienced during the record cold in December 1989. Overcoming these concerns may require, in part, more effective communication with users regarding improvements in the capability of the industry.

Not all of the concerns identified are subject to resolution by the transmission and storage industry. In addition, many concerns, particularly the uncertainty with the new service arrangements mandated under Order 636, how they will affect both the suppliers and users of natural gas, and the impact of transitional costs on the ability of the industry to finance new construction, will not be fully resolved for some time.

While there are substantial regulatory uncertainties associated with business operations in the industry, the uncertainty of the regulatory process is being replaced in many instances by the market uncertainty. Thus, uncertainty is not a reason to stand still. The industry can address directly many concerns highlighted by the focus groups, such as operational guidelines and coordination. In other areas, services offered by the industry will need to incorporate means to mitigate the risk associated with market and regulatory uncertainties and address customer concerns regarding the reliability of the network system.

The transmission and storage industry is in the process of redefining its role and reshaping its business operations to meet the needs of the industry in the future. A commitment to addressing the concerns identified in the focus groups and expressed by NPC study participants will:

- Allow pipeline customers to obtain the type and quality of service that they need
- Allow the pipeline industry to position itself for the realities of the marketplace under the restructured regulatory environment
- Ultimately, enhance the potential for increased use of natural gas.

APPROACH TO ISSUES AND RECOMMENDATIONS

Focus groups and other NPC study groups have highlighted significant areas of concern relating to the transmission and storage industry that are impediments to the increased use of natural gas.

The Transmission and Storage Task Group has isolated eight issues that they believe are particularly critical to allowing the transmission and storage industry to participate in the challenge to increase the use of natural gas.

In subsequent chapters, these issues are discussed in detail and recommendations provided to eliminate or mitigate constraints to the increased use of natural gas.

ISSUES AND RECOMMENDATIONS

CHAPTER THREE
SUMMARY OF RECOMMENDATIONS

INTRODUCTION

The findings of the Transmission and Storage Task Group indicate that the transmission and storage industry has in the past and is now actively pursuing the expansion of facilities and services to meet increasing customer demands. The reshaping of the industry requires the development of innovative approaches to provide economic, efficient, and reliable service.

The general recommendation of the Transmission and Storage Task Group is "Participants involved in the transmission and storage system should take specific actions to improve the system's ability to provide economic, efficient, and reliable natural gas service responding to customer needs."

Eight specific issues are particularly critical to allowing the industry to improve transmission and storage services. Each of these issues are discussed in detail in this section and recommendations are provided that, if implemented, will enhance the ability of the industry to develop innovative and customer-responsive services in the delivery of natural gas. The issues are as follows:

- Incentive Regulation and New Services
- New Facilities
- Reliability and Industry Operating Guidelines
- Access to Pipeline and Storage Capacity
- Environment and Safety
- Serving Electric Generation Loads
- Gathering
- Technology.

INCENTIVE REGULATION AND NEW SERVICES

Industry and regulators should continue the evolutionary process toward deregulation in competitive markets and incentive regulation in those markets where competition has not been shown to exist. Such initiatives should be structured to foster reduced costs, increased efficiency, and encourage new and innovative services that are responsive to customer needs. The impacts of these regulatory changes are expected to include:

- Increased efficiency and reduced costs
- Minimized new facilities requirements
- Lowered regulatory compliance costs
- Increased investments in technology
- Improved ability to serve customers.

NEW FACILITIES

Overall, the industry must improve its ability to construct new facilities on a timely basis.

- The industry should adopt and communicate to its customers a philosophy of **working with customers to install facilities**

required for economical, efficient, and reliable services responsive to customer needs.

- In competitive markets, the Federal Energy Regulatory Commission (FERC) should allow implementation of market-based pricing using negotiated rates.
- In noncompetitive markets, the FERC should mitigate risk conditions and encourage alternative incentive-based rate structures.
- The FERC should establish risk/return parameters at time of regulatory approval that remain stable over time.
- The industry should reduce the delays associated with the construction of new facilities by:
  - Working with the FERC and other federal, state, and local agencies to expedite the review and approval process for new pipeline projects without diluting substantive environmental protections (see Chapter Eight).
  - Working with the FERC and other agencies to reduce non-environmental delays.
- The industry and regulators should minimize the cost of new facilities.
  - Minimize new facility requirements.
  - Encourage efficient use of storage.
  - Encourage development and use of new technology.

RELIABILITY AND INDUSTRY OPERATING GUIDELINES

The industry should expand its work with customers to address specific reliability concerns.

- Consider the formation of a national voluntary organization to assist during periods of operating stress.
- Create an industry master contact list of pipeline and producer operators.
- Coordinate maintenance and downtime schedules.
- Consider the formation of a Natural Gas Reliability Council to help coordinate and facilitate specific ways to address reliability issues (as discussed more fully in Volume I, the summary report).

The industry needs to make it easier for customers to buy and transport natural gas through activities such as the development of industry operating guidelines.

- Support and expand on efforts made by the Interstate Natural Gas Association of America and the Council of Petroleum Accounting Societies (INGAA/COPAS) and GAS*FLOW
- Simplify and improve consistency among transportation request forms
- Develop a consistent set of rules governing the allocation of capacity (upstream vs. downstream) at capacity constrained points
- Improve efficiency and timeliness of service through appropriate use of:
  - Electronic Data Interchange to transfer information,
  - Agreement, such as operation balancing agreements,
  - Procedures, such as predetermined allocation procedures, and
  - Use of on-line real-time measurement when appropriate.

The industry, perhaps through the Natural Gas Reliability Council, should fully evaluate the recommendations of the FERC/DOE Deliverability Task Force and assist in the implementation of these recommendations as necessary.

Federal, state, and local officials should support the industry's efforts to address reliability and industry operating guideline issues that improve the overall quality of service to natural gas consumers.

- Address potential conflicts at federal and state levels between the regulatory framework and contracts, e.g. end-use curtailment, service obligations.

ACCESS TO PIPELINE AND STORAGE CAPACITY

The natural gas industry needs to develop better methods to communicate to customers the availability of transmission and storage capacity.

State regulatory authorities need to evaluate, and direct, as appropriate, the unbundling of natural gas sales from transmission and storage services by local distribution companies (LDCs) and intrastate pipelines in order to further the general objectives of FERC Order 636, and to encourage the more effective marketing of natural gas services by LDCs.

The industry needs to encourage the creation and recognition of market hubs as mechanisms to promote better market access and improved reliability of natural gas services.

ENVIRONMENT AND SAFETY

A streamlined regulatory process would enhance the competitiveness of natural gas and, in turn, its desirable environmental effects. Many of the regulatory requirements are avoidably slow and redundant. The Transmission and Storage Task Group makes the following recommendations for eliminating wasteful procedural constraints on the industry without diluting substantive environmental protections. The natural gas industry should:

- Actively promote to regulators, environmental interest groups, and the general public the environmental and safety benefits of increased use of natural gas as an energy alternative.
- Actively promote to regulators, environmental interest groups, and the general public the environmental and safety benefits derived from a buried transportation system.
- Work with the Federal Energy Regulatory Commission and other federal, state, and local agencies to expedite the review and approval process for new pipeline projects without diluting substantive environmental protections.
- Aggressively promote and fund the development of emission control and retrofit technology for compressor prime movers, and more efficient, cleaner burning new prime movers, to meet increasingly stringent emissions requirements.

SERVING ELECTRIC GENERATION LOADS

The natural gas and power generating industries must cooperate, coordinate, and compromise to make this transporter/customer relationship work.

The natural gas industry must develop creative and tailored services to encourage flexibility and commitment to gas by the electric utilities.

GATHERING SYSTEMS

Gathering systems are a critical link in aggregating natural gas from the wellhead, providing processing and treating services, and delivering merchantable natural gas to intra- and interstate pipelines. Unbundling of gathering systems as a result of FERC Order 636 has focused attention on the potential impact on rates for gathering on individual gathering systems that were previously subject to "rolled-in" treatment. Stability in gathering fees for producers and consumers and acceptable economic returns for gathering systems owners will best be accomplished by unbundling, open access, and market forces. Oversight at the state level may be indicated in isolated cases; but regulation is not an acceptable alternative for the industry where sufficient competition exists.

TECHNOLOGY

The gas industry should continue to support the development and deployment of new technologies to meet the needs of the gas transmission and storage industry and its customers.

The gas industry should work with regulators to create mechanisms, such as incentive regulation, to ensure that the benefits of new technology development accrue to those that assume the risks and bear the costs (as discussed in the Technology chapter of Volume I, the summary report).

CHAPTER FOUR

INCENTIVE REGULATION AND NEW SERVICES

Recommendation — Incentive Regulation and New Services

Industry and regulators should continue the evolutionary process toward deregulation in competitive markets and incentive regulation in those markets where competition has not been shown to exist. Such initiatives should be structured to foster reduced costs, increased efficiency, and encourage new and innovative services that are responsive to customer needs. The impacts of such initiatives would be:

- Increased efficiency and reduced costs
- Minimized new facilities requirements
- Lowered regulatory compliance costs
- Increased investments in technology
- Improved ability to serve customers.

The dialogue concerning competition in markets and the costs and benefits of the various forms of interstate pipeline regulation continues to evolve. The natural gas industry, the FERC, and state regulatory bodies are attempting to come to grips with the reality of cost-based regulation in a free market context. Sensitive to the dangers of unchecked market power, regulators are nonetheless aware that incentives may be desirable to ensure the financial health of pipelines and that natural gas customers receive the broadest array of low cost, quality services possible. This section addresses these issues, focusing on incentive regulation and its potential benefits, including new services.

COMPETITION IN MARKETS AND MARKET-BASED RATES

On September 17, 1992, the FERC held the first meeting of the Task Force on Pipeline Competition. The intent of this meeting was to define the scope of the inquiry and the issues to be addressed. The task force's goal is to identify, evaluate, and recommend methods for assessing competition in transportation markets.

The importance of competition in markets as it pertains to regulatory change is underscored by the FERC's pipeline competition study. In the past, the FERC has taken the position that where markets can be found to be workably competitive, market- or value-based pricing can replace cost-based pricing. A market is defined as workably competitive when no party has sufficient market power to arbitrarily affect the prices, i.e., competitive forces are adequate to regulate the market. Unfortunately, to determine that a market is workably competitive has historically been a highly complex and time consuming process.

To the extent that the FERC is successful in identifying or developing methods to assess the existence and degrees of competition, we can expect some markets to be properly categorized as workably competitive. It is quite possible these markets could be subject to deregulation and resulting market-based rates. However, it is certain that other markets are noncompetitive and will continue to be regulated. In these cases, incentive regulation may represent a desirable alternative to traditional cost-based regulation.

INCENTIVE REGULATION

In September 1989, the FERC issued its staff technical paper on incentive regulation. The FERC staff concluded that "pipelines had little incentive or ability to design demand-responsive rates, market their services aggressively, or seek innovative ways to improve service and minimize costs" because of the constraints of cost-based regulation. Subsequent developments culminated in the March 1992 release of the FERC's *Notice of Proposed Policy Statement on Incentive Regulation.* Here, the Commission proposed key elements of an incentive rate-making policy and guidelines for companies to use in developing individual rate schemes. It stated that the Commission was interested in providing alternatives to traditional cost-of-service regulation for companies with market power. To better understand the impetus for the FERC's evolving views on incentive regulation, the concepts of cost-based regulation and incentive regulation are briefly discussed.

Traditional Cost-Based Regulation

Cost-of-service regulation directly ties the rates or prices that can be charged for a service to the allowed costs of providing that service. Allowed costs include operating and maintenance costs, general and administrative costs, depreciation, interest, taxes, and return on capital.

There are several consequences of cost-of-service regulation. First, any change in cost that is prudently incurred is passed directly to the customer in the next rate case. What is not apparent is the incentive, of the regulated entity to reduce expenses, particularly out-of-pocket expenses such as operating and maintenance costs. Second, since the regulated entity's return is based on invested capital, it has an incentive to increase rate base. Third, rates are adjusted to reflect utilization. As long as the facilities are "used and useful" they are included in rate base. Therefore, any increase or decrease in throughput will be reflected in new (lower or higher) rates in the next rate case.

Incentive Rate Mechanisms

Incentive rate structures are designed to overcome many of the deficiencies inherent in cost-based regulation. Insuring that these efficiencies are achieved is the job of the regulator, but there is a wide body of thought that maintains that the profit motive is a much more effective approach. Among the incentive rate mechanisms widely discussed are the following:

- ***Price Caps*** – Rates are initially determined based on cost-of-service, but any change is determined by an index. The index is normally designed to cover the cost of inflation and adjust for changes in productivity. Since the revised rates are not tied directly to the actual cost-of-service, the entity has a significant incentive to reduce costs, increase throughput, and to invest only in those activities where the marginal cost is less than the prevailing rates.
- ***Zone of Reasonableness*** – A range of returns is established within which the company agrees to not file a rate case, provided the returns fall within the specified range. Effectively, within this range, cost-of-service and rates are uncoupled. This approach therefore has the same benefits as the price cap structure.
- ***Bounded Rates*** – Cost-of-service rate making generally relies on original cost. Since many pipelines are highly depreciated, original cost holds little or no relation to the market value of the service. If the rate the customer is charged is significantly below the market value, the resulting demand for the service will exceed free-market demand. This result is economically inefficient because it distorts society's demand for the service relative to other goods and services. Bounded rates attempt to solve this problem by allowing the company to establish a range of rates. For example, the upper bound could be based on replacement cost of

facilities while the lower bound could be based on the original cost of facilities. Since the company is free to charge any price within these boundaries, productive efficiency is achieved while simultaneously achieving allocative efficiency.

- ***Efficiency Gains*** – This is a sharing mechanism that, in general, focuses on parameters that are easily measurable, e.g., operating costs or throughput. The benefits or costs of any measurable change in these parameters are shared among the customers and the company on a predetermined basis. This creates a direct relationship between how a company performs relative to these parameters and the company's income.
- ***Incentive Rates of Return*** – This is a performance based concept. The regulated company is awarded an incentive return, e.g., a one-quarter percent higher return on equity, for achieving a specific performance level. This approach has been used extensively in government contracting.

While discussed separately, many of these concepts can be combined to achieve a specific objective. For example, the price cap could be combined with a sharing of productivity improvements so that both the customer and the company have the opportunity of receiving some benefit.

Incentive rates are in wide use throughout the United States and other industrialized countries. Rate cap regulation has been applied to two of our largest industries—railroads and long-distance telephone service. The U.S. railroad industry has used rate caps since 1981 and in 1989 the Federal Communications Commission approved rate indexing for AT&T. Rate caps have been applied to British Telecom since privatization in 1984 and to British Gas since 1986. Sharing of efficiency gains is widely used throughout the distribution sector of the gas industry and many states, including California, are considering much wider application.

Benefits of Incentive Regulation

Cost-based regulation does not create optimal incentives for pipelines to minimize costs, increase capacity utilization, or introduce new services. Pipelines are less inclined to seek efficiency gains through organizational change or new technology development because these would be lost at the next rate review. To some extent, these problems have inhibited the development of innovative pricing and marketing strategies and have contributed to the perception that the pipeline industry is not market or customer oriented.

For the pipeline industry, incentive regulation can increase the potential for greater returns by encouraging cost reductions and throughput increases. Other benefits include increased flexibility to respond to competition, lower regulatory and outside services costs because of fewer rate filings, and greater rate certainty and stability. In such an environment, pipelines would be prone to spend more for research and development to yield technology-driven gains in productive efficiency. In addition, incentives would stimulate the timely creation of new services.

New and Innovative Services

The focus groups' comments include the following statement:

> *Participants believe that the gas industry and its regulators show little interest or respect for the needs of its customers. Rates and sales programs of pipelines, producers, distributors, and marketing companies are designed to be operationally convenient for the supplying segment rather than designed to address the operational needs of the customers. Accordingly, customers do not obtain the services that they want and to which they attribute value above the value inherent in the commodity.*

To address these perceptions the natural gas industry needs to improve, materially and visibly, its record of providing the services its customers desire. Fortunately, there are a number of contemporary examples of new services, the results of creativity and innovation, which demonstrate what can be achieved if the proper incentives exist. These examples are not isolated within one or two segments of the industry, but appear throughout the industry. Notable among these new offerings are:

- Gas supply aggregation programs, whereby a gas marketer provides small independent producers the opportunity to obtain higher prices for their production and compete with major producers and large independents by pooling supplies.

- Innovative pipeline transportation and storage programs that offer higher quality services at less cost than traditional alternatives. One example is an interstate pipeline's recently introduced off-peak firm transportation service. This service is offered under firm transportation terms except during certain months, when service can be interrupted for periods up to 30 or 60 days, whichever the customer chooses. Another example is an experimental market-responsive storage and delivery service offered by an interstate pipeline. Here, rates for the storage and delivery service are negotiated up to a price cap, and a revenue-sharing mechanism is implemented when all capacity is sold and more than the facility's cost-of-service is recovered.
- Natural gas services companies. One such company markets a portfolio of fuels to customers with the ability to switch fuels when economics or other conditions dictate. This service provides customers with the lowest priced BTU available under contract.
- Companies that promote natural gas as the clean fuel alternative for transportation. Numerous firms have entered this market, offering a full palette of services including natural gas vehicle conversions, refueling infrastructure development, and natural gas sales.

These examples show that the natural gas industry has the ability to develop and offer innovative services to its customers. In many of today's new service programs, the services are offered in a non-regulated, free-market environment or represent regulator's attempts to implement lighter-handed regulation. Ultimately, the proliferation of such services hinges upon the existence of adequate incentives to encourage risk-taking necessary to develop new services and the confidence to offer them.

The benefits of incentive regulation and new services are expected to accrue to end users as well as other sectors of the natural gas industry. To test this premise, a sensitivity analysis was performed on NPC Reference Case 1 (the moderate energy growth scenario). This analysis incorporated a compounded 2 percent real reduction in pipeline industry costs to simulate the effects of incentive regulation and new services.

The Incentive Regulation/ New Services Case

In the Incentive Regulation/New Services Case, all components of pipeline industry costs were adjusted downward 2 percent per year (in real terms) compared to Reference Case 1. Capital costs for new construction, operations, maintenance, and replacement costs were included in the pipeline costs category. Cost reductions were first realized in 1995, so that by 2010 pipeline transportation margins were 30 percent less than they would have been without the decrease. These reductions were fully reflected in reduced transportation rates, while pipelines were assumed to receive full cost recovery beginning in 2000. A 2 percent annual rate for cost reduction was selected by a consensus of the members of the Transmission and Storage Task Group as a reasonable level for the sensitivity analysis. The task group was unable to develop data indicating whether this level of cost reduction would actually be achievable.

The potential industry-wide impact of reduced transportation costs is indicated by the results of the Incentive Regulation/New Services Case (as compared to Reference Case 1):

- End-use gas demand increases by 0.3 trillion cubic feet (TCF) in 2010 and by a cumulative 1.7 TCF during the 1995-2010 period.
- Lower-48 cumulative reserve additions increase 2.5 TCF.
- Lower-48 average wellhead gas prices do not significantly change over the 16-year period.
- Pipeline transportation margins decrease, achieving a 30 percent ($0.17 per million BTU) reduction by 2010.
- Customers save more than $30 billion during the 1995-2010 period.

In this scenario, end-use demand increases a cumulative 1.7 TCF over that in Reference Case 1. Of this, 2.0 TCF is attributable to increased consumption in the residential, commercial, and industrial sectors, which is offset by a 0.3 TCF decrease in electric generation demand. This arises out of a shift from electricity consumption to gas consumption by end users and defers construction of new electricity generating plants. Increases in cumulative reserve additions of 2.5 TCF occur and supply elasticity results in average wellhead prices that exhibit no significant increase in the analysis period. These supply-side factors and the savings from decreased transportation rates combine to yield a lower delivered gas cost. This drives the increases in non-electric generation demand and results in a net cost reduction to customers in excess of $30 billion over the 15-year period.

The Incentive Regulation/New Services Case demonstrates the benefits that may be possible from increased productivity and cost efficiencies arising from incentive regulation of interstate pipelines and new services. The potential for additional consumptive demand of nearly 1.7 TCF (cumulative) implies that the benefits of these gains could be shared across all sectors of the natural gas industry. In any case, as natural gas consumption increases, whether due to presently projected growth or the additional growth that may result from incentive regulation, natural gas customers will continue to seek a greater variety of services to satisfy their needs.

CONCLUSION

Incentive regulation and new services clearly have a role to play in the natural gas industry. In noncompetitive markets, they can facilitate the actions necessary to achieve the results of the Incentive Regulation/New Services Case. In this scenario, operating costs and capital expenditures are reduced, resulting in savings for customers and providing pipelines the opportunity to increase returns. How the concepts of incentive regulation should be applied is a case specific determination. Because of the unique characteristics of pipeline companies and their markets, the use of incentive regulation in the pipeline industry will likely result from individual rate cases and settlement negotiations.

Chapter Five

New Facilities

ISSUE IDENTIFICATION

As the study of the existing transmission and storage network within the U.S. shows, adequate capacity exists to serve the current market using the present system supply configuration. However, as gas supplies shift on a regional basis, and as markets continue to grow and shift geographically, the need for pipeline companies to expand capacity via new pipeline systems, looping, and/or storage facilities will continue. The installation of these new facilities will depend to a large degree upon the natural gas industry's ability to address and resolve several issues identified and supplemented by the focus group study. **Six issues identified by the Transmission and Storage Task Group include cost recovery mechanisms, throughput conditions, regulatory uncertainty, delays, the cost of new facilities, and the overall financial health of the pipeline industry.** An understanding of each of these issues is important as a foundation to the recommendations presented in this section.

Cost Recovery Mechanisms

Much concern has been raised about the best rate structure for recovering the cost of new facilities. Attempts at addressing the issue of who bears what portion of the cost of new facilities have occurred in the form of rate making philosophies ranging from incremental[1] to rolled-in.[2] Some argue that spreading costs to all customers via rolled-in rates unduly penalizes existing customers who do not directly benefit from specific projects. Others contend that incremental rates place too much cost on new customers who may derive some, but not all, of the benefits from the new facilities. For example, the proposed Transco Southeast Lateral Expansion Project was canceled due to a disagreement between Transco and its ratepayers over rate structure (Transco's customers opposed Transco's proposed rolled-in rate treatment). Obviously, each industry stakeholder stands to benefit from one rate making strategy over another. Unfortunately, no single methodology always distributes costs equitably among all parties.

Throughput Conditions

The ability of the pipeline industry to meet throughput conditions imposed by the FERC is one issue that was raised. Many express concern over the pipeline throughput required to maintain profitability and reasonable risk/return parity given rate designs and at-risk conditions. As an example, currently

[1] Incremental rate design is a methodology used in designing rates for new facilities, which assigns the entire costs associated with new facilities to the customers receiving services from the new facilities.

[2] Rolled-in rate design is a methodology used in designing rates for new facilities in which the incremental costs and throughput volumes associated with the new facilities are included in the system wide rates of the pipeline constructing the facilities. Typically, rolled-in rate treatment is used when there is a net benefit for the existing customers, or other benefits in the form of new revenues in excess of the cost of the facilities placed in service.

Recommendations — New Facilities

Overall, the industry must improve its ability to construct new facilities on a timely basis.

- The industry should adopt and communicate to its customers a philosophy of **"working with customers to install facilities required for economical, efficient, and reliable services responsive to customer needs."**
- In competitive markets, the Federal Energy Regulatory Commission should allow implementation of market-based pricing using negotiated rates.
- In noncompetitive markets, the FERC should mitigate risk conditions and encourage alternative incentive-based rate structures.
- The FERC should establish risk/return parameters at time of regulatory approval that remain stable over time.
- The industry should reduce the delays associated with the construction of new facilities by:
  - Working with the FERC and other federal, state, and local agencies to expedite the review and approval process for new pipeline projects without diluting substantive environmental protections (see the Environmental section of this chapter).
  - Working with the FERC and other agencies to reduce non-environmental delays.
- The industry and regulators should minimize the cost of new facilities.
  - Minimize new facility requirements.
  - Encourage efficient use of storage.
  - Encourage development and use of new technology.

proposed regulation requires rates based on high throughput requirements calculated close to maximum allowed operating pressures. Gas transmission companies are placed at risk to keep their pipelines full. This risky environment forces pipelines to face the formidable downside risk of not maintaining a "full" pipeline without the benefit of the upside potential attained by higher levels of throughput.

Regulatory Uncertainty

Much apprehension has been expressed over the stability of the policies generated by the regulators of interstate pipelines, and the ability of these pipelines to enter into long-term agreements under such an environment. Again, focus group participants asserted many concerns aimed primarily at the regulators:

> *I think the importance of certainty is critical. We're trying to put together a [power generating] entity that's going to be based on long-term contracts. To go into something and not know whether it's rolled-in or incremental until a couple of years down the road is not possible.*

> *Things have been changing so fast, you finally think you're starting to understand what the ground rules are and they change again.*

The concerns of task group members and focus group members alike echo several important aspects of the regulatory stability issue. First, all participants in the industry have a strong desire to maintain the certainty of their contracts, regardless of changing regulations. When regulations change, thereby nullifying those contracts (as has happened in the past), the binding nature of those contracts are compromised. One focus group member declared:

> *I suggested to one of the commissioners that we need to have sanctity of contracts. He said, "Oh no, we can't have that. There is no way we can move forward worrying about contracts."*

Also, the differences between state and federal requirements and regulating philosophies create confusion and frustration.

> *You get the federal government in here and the states and at certain times they're opposed to each other's thrusts and views.*

The net effect of this unstable regulatory environment is a reluctance of pipelines and their customers to enter into long-term agreements that require the construction of permanent facilities, and an aversion by the financial markets to supply capital to build those facilities.

Delays

Concern exists over excessive delays experienced during the period of time between the inception and completion of new facilities. Delays inhibit the industry's ability to be responsive to their markets. Environmental review and reporting requirements coupled with the ability of special interest groups and competitors to delay construction through protests and proposals of duplicate facilities extend the approval process time to unreasonable extremes. For example, due to a regulatory approval process that was clogged by the filing of a multitude of alternative facilities and interventions, the Kern River (a 450-mile pipeline) project approval process spanned over five years while taking just one year to build. Iroquois Pipeline is yet another example where multiple interventions bogged down the approval process. Additionally, lengthy and complex applications are often filed incomplete, further clogging the regulatory review process. The ultimate result of these delays is a loss of competitiveness by the pipeline industry. Customers may be drawn to other energy suppliers who require less time to install facilities. The FERC is cognizant of these issues, however, and has worked diligently to speed the approval process. In fact, since 1988 the FERC has approved the construction of over 10,000 miles of new natural gas pipeline facilities at a cost of about $11 billion.

Cost of New Facilities

The total cost of constructing and installing new facilities may be a constraint to adding new capacity. Facility costs and the related transportation rates may make natural gas an noncompetitive choice when the delivered cost of natural gas competes with the delivered cost of other energy alternatives. Consequently, any actions to reduce the cost of new facilities consistent with efficient and reliable service can serve to make natural gas more competitive in serving new markets.

Overall Financial Health of the Pipeline Industry

The focus group participants communicated a genuine concern over the financial strength of the pipeline industry. They stated that take-or-pay settlements and the transition costs of FERC Order 436 have undermined the financial health of interstate pipeline companies, and will make the investments required to expand capacity more difficult to finance. One focus group participant who expressed the sentiments of many stated:

> *Everybody basically, with the exception of probably two or three companies, [are] teetering on the investment grade ratings.*

Another typical viewpoint that focus group participants expressed:

> *You're finding the lenders being more and more conservative because of regulatory uncertainty in this industry.*

Several major pipeline transmission companies have had to restructure organizationally and financially to remain competitive. For example, Columbia is currently undergoing Chapter 11 bankruptcy proceedings as a result of many of the concerns identified by the focus groups and this has made it difficult for Columbia to receive regulatory approval for at least one new project.

The industry is developing structures that allow the incremental financing of new pipeline facilities. Kern River and Mojave are two examples of the gas pipeline industry's ability to build facilities to meet customer needs in today's constrained financial environment.

WORKING WITH CUSTOMERS

Many of the above issues relate to the regulation of the pipeline industry. Regulators can allow the natural gas industry more flexibility and certainty so that it can work within a free market environment. In turn, pipelines must work diligently within a light-handed regulatory approach to make the free-market concept succeed. A philosophy that will assist the industry's commitment to install the facilities necessary to serve a growing market is:

> **Working with customers to install facilities required for economical, efficient, and reliable services responsive to customer needs.**

The NPC recommends that the industry adopt and communicate this philosophy to its customers. Providing that service through the installation of new facilities at a competitive price and in a timely manner is predicated on appropriate regulation in a free market environment. History has shown that energy demand has always been met . . . at a price. What remains to be written, is whether future demands will be satisfied by natural gas or some other energy source. The following additional recommendations present concrete actions that are necessary to eliminate the regulatory and cost constraints to adding new capacity to the nation's pipeline infrastructure, and help ensure that natural gas becomes and remains the nation's energy of choice.

REGULATORY CONDITIONS ON NEW FACILITY CONSTRUCTION

A primary hurdle facing the natural gas industry in its attempts to add new facilities is providing a framework that maintains equitable sharing of costs and risks between producers, pipelines/transporters, marketers, and end users. Traditionally, the control of the equitable risk/return of existing pipeline expansions and new pipeline systems has rested in the hands of regulatory agencies (primarily the FERC). The present regulatory conditions placed on new facilities certification create risks that, when compared to the anticipated returns, make it difficult to support the financing requirements of many new construction projects. The financial community voiced concerns about the impact of regulation on project-financed pipeline construction in comments to RM91-11-000 [MEGA-NOPR] in October 1991. Essentially, the risk/return issue is rate and regulatory in nature, and therefore can only be solved through changes in the regulatory process.

In Competitive Markets, Implement Market-Based Pricing Using Negotiated Rates

Market-based pricing should be implemented where adequate competition exists. Only through unimpeded free markets can parity be reached between the risk of building new pipeline facilities and the returns that these assets produce. To the extent that the need for new or additional pipeline capacity is not clearly defined, investors willing to assume risks should be allowed to pursue those opportunities and accept the responsibility for their actions. The best rate making lets the market act freely through rates that are negotiated between pipelines and their customers. The FERC and other regulatory agencies should encourage the use of "negotiated rates" for new facilities as an alternative to traditional approaches.

Negotiated rates do not preclude the negotiation of a rolled-in rate treatment with a pipeline's customer base or a particular customer group. For example, pipelines might pursue rolled-in treatment in their negotiation of cost recovery for the connection of new supplies. Eventually every customer will be faced with the prospect of adding/connecting new supplies. Sharing the cost burden throughout the system creates an incentive to expand, and while the cost of the expansion creates a small rate increase to all customers, they can benefit from the added supplies.

An example of negotiating incremental rates is the expansion of mainline and lateral lines in the direct vicinity of a particular customer or adding new customers. Only the specific customer stands to benefit from these facility additions. Therefore, a negotiated incremental rate is more likely and would occur only if the incremental costs of the new facilities are economically feasible for the customer (or whomever is paying for the facilities) when compared to other alternatives.

Of course, incremental or rolled-in rate treatment can apply to either market area or supply area expansions. Regardless of whether rates end up rolled-in or incrementally charged to specific customers or customer groups, rates should be determined through free and open negotiations. Obviously, the free market approach is only applicable where competitive markets exist.

In Noncompetitive Markets, Mitigate Risk Conditions, and Encourage Alternative Incentive Based Rate Structures

In noncompetitive markets, currently proposed risk conditions should be replaced with a mechanism that allows investors to recover costs and receive a rate of return that recognizes the project's overall risk. Overall risk is actually comprised of many components that vary depending on project type and location. For example, risks inherent in supply area projects include expectations of reserve life and recovery mechanisms. Risks in market area projects include expectations of market growth. Risks such as regulatory uncertainty are common to all projects. Thus, while a fixed rate of return may encourage the construction of new facilities for a given project, it may not result in the most economically prudent venture for all of the natural gas industry stakeholders. Ideally, in noncompetitive markets, regulators should work toward rate structures where suppliers (producers), purchasers, and pipelines all share in a project's risk. For example, in supply areas, if a particular geological basin shows good potential for future development, pipelines should be able to install supply area transmission/gathering facilities with "extra" capacity without having to fulfill the proposed maximum throughput requirements. The economics of installing a larger diameter pipeline initially are much more favorable than looping a smaller diameter line at a later date. The Mobile Bay project is an example of a viable supply attachment whose certificate was not accepted due, in part, to high throughput requirements. Rates should be based on throughput levels that balance both upside and downside potential while mitigating risk-shifting. Regardless of what actions are taken to mitigate the at-risk dilemma, all segments of the industry must reach a consensus on how risk should be allocated.

In addition to mitigating risks, alternatives to traditional rate structures are needed in noncompetitive markets that encourage the installation of new facilities at minimal costs. A relatively new approach that has been successfully introduced in other industries (telecommunications, for example) is incentive based rate making. This new methodology, examined in detail in Chapter Four, demands further examination and prospective adoption by the gas industry and the FERC.

Establish Risk/Return Parameters at Time of Regulatory Certification That Remain Stable Over Time

New customers and project sponsors need assurance that their costs will remain stable over the long term. Both long-term and short-term contracts should allow a rate of return that is related to the term of the contract. Pipelines and their customers must feel comfortable about entering into long-term agreements and making capital expenditures with confidence that the FERC or any other regulatory entity will not change policy or rules at the pipelines' next rate case. The FERC must remain forward looking and provide certainty in its policy decisions. Flexible regulation must be established that reduces the uncertainty customers face when attempting to develop long-term energy supply portfolios. The best way to assure new customers and project sponsors that their costs will remain stable over the long term is to establish project risk and return parameters at the time of project certification and demonstration that these parameters will remain stable over time.

Reduce Delays Associated With the Construction of New Facilities

The pipeline industry and regulatory entities must work together to reduce delays. **First and foremost, the environmental review process must be streamlined.** A more in-depth analysis of environmental issues facing the industry is presented in Chapter Eight.

The pipeline industry must work diligently with the FERC to reduce non-environmental delays as well. First, all segments of the gas industry should work together to avoid protracted delays resulting from the raising of frivolous due-process concerns and filing questionable competitive applications. Also, companies filing joint proposals should improve coordination to insure that their applications are filed complete and with minimal subsequent revisions. Finally, the concept of a phased certification process[3]

[3] Under phased certification, the FERC will issue a preliminary certificate addressing business issues prior to a full order on all environmental issues. This allows companies to order materials, obtain financing, and take other actions necessary to install new facilities earlier than if the FERC waited to address all business and environmental issues in a single certificate.

should continue to be pursued by the FERC as it reconsiders Order 555.

COST OF FACILITIES

Finding alternatives to high-cost facilities is of paramount importance when customers weigh the cost of gas service against other options. Minimizing new facility requirements through the more efficient use of existing facilities, and the utilization of new technology are methods that can reduce the overall cost of facilities. Additionally, an overall increased use of natural gas will help reduce the "effective" cost of facilities by reducing the uncertainty that markets will be there to support the new facilities, and by providing larger throughput volumes over which to spread the added cost of service. However, the entire natural gas industry must cooperate in its efforts to add new customers and increase usage/throughput if it expects to grow during the next decade.

The first step in reducing costs is to minimize new facility requirements. Incentives are needed that encourage the industry to offer new services that meet customer requirements while minimizing the need for new facilities. For example, offering 330-day off-peak firm service to customers provides an opportunity to reduce the need for those facilities required to provide the peaking service during periods of high demand.

Efficient use of storage is another alternative to building expensive new facilities. Storage utilization varies significantly between pipeline companies, so it is difficult to prescribe one specific method for improving efficiency. However, in general, maximum efficiency is gained through the cycling of top gas (that gas which is available for withdrawal) during peak demand periods. Storage fields should be developed to meet a pipeline's specific system design. Pipelines with excess storage capacity should work to more fully utilize that capacity in lieu of building new facilities. It is important to note that the FERC Order 636 mandates that all participating open-access pipelines offer capacity release programs. These programs will allow those who have firm contractual capacity rights to release those rights to others. These programs offer the potential to increase pipeline utilization by creating a more efficient market for pipeline capacity. Moreover, the programs will provide the market with a flexible tool that may support market expansion without the need for new facilities.

The development and use of new technology should be encouraged. Technological improvements in materials and processes should be fully exploited to reduce the costs of new facilities and the costs of modifications to existing facilities. Incentives such as special rate treatments and tax incentives are needed to spur the use of new technology, as it is usually quite costly to implement. Technology is a subject that cuts across more than just the ability to add new facilities, so an in-depth discussion is presented in Chapter Eleven.

Chapter Six

Reliability and Industry Operating Guidelines

The focus group summary defined the reliability issue in five parts: (A) pipeline deliverability; (B) regulatory environment; (C) supply deliverability; (D) price volatility; and (E) marketing companies.

The (A) **pipeline deliverability** issue is defined as having three parts:

- Capacity limitations, or lack of sufficient capacity
- Financial health of the pipeline industry (to the extent it affects the industry's ability to add new facilities)
- Operating procedures, particularly as they relate to serving industrial, independent power producer, and electric utility loads.

The first two parts of the pipeline deliverability issue are addressed in the New Facilities and Assets sections. Consequently, this section will focus on the pipeline deliverability issue as it specifically relates to operating procedures.

Operating procedures are directly related to the reliability issue and are also a key part of serving natural gas customers. As an example, in December 1989, there was a stress situation where it appears that the availability of additional real-time data might have improved the industry's ability to respond to these circumstances. Other examples include circumstances where pipelines might not have fully coordinated operating procedures, including but not limited to:

- Lack of an industry contact list of pipeline and producer operators to be used in periods of operating stress
- Lack of coordinated maintenance and downtime schedules
- Lack of consistency among transportation request forms
- Lack of a consistent set of rules governing the allocation of capacity (upstream vs. downstream) at capacity constrained points.

Improved operating procedures also have the ability to enhance the efficiency of natural gas service. Examples include the use of predetermined allocation procedures, operating balancing agreements, use of Electronic Data Interchange to transfer information and increased use of on-line, real-time measurement for billing, as well as operational purposes.

The (B) **regulatory environment** presents reliability issues as well. While FERC Order 636A tries to preserve and enhance the reliability of the transmission and storage system by encouraging increased use of real-time measurement and other means, there are other regulatory issues that arise in the area of the reliability of the transmission and storage system. Specifically, there is potential conflict between curtailment plans based on end use as provided in the Natural Gas Policy Act of 1978 and the Order 636A environment where supplies are envisioned to be allocated on the basis of contracts. As background, many

Recommendations — Reliability and Industry Operating Guidelines

The industry should expand its work with customers to address specific reliability concerns.

- Consider the formation of a national voluntary organization to assist during periods of operating stress.
- Create an industry master contact list of pipeline and producer operators.
- Coordinate maintenance and downtime schedules.
- Consider the formation of a Natural Gas Reliability Council to help coordinate and facilitate specific ways to address reliability issues (as discussed more fully in Volume I, the summary report).

The industry needs to make it easier for customers to buy and transport natural gas through activities such as the development of industry operating guidelines.

- Support and expand on efforts made by the Interstate Natural Gas Association of America and the Council of Petroleum Accounting Societies (INGAA/COPAS) and GAS*FLOW
- Simplify and improve consistency among transportation request forms
- Develop a consistent set of rules governing the allocation of capacity (upstream vs. downstream) at capacity constrained points
- Improve efficiency and timeliness of service through appropriate use of:
  - Electronic Data Interchange to transfer information,
  - Agreement, such as operation balancing agreements,
  - Procedures, such as predetermined allocation procedures, and
  - Use of on-line real-time measurement when appropriate.

The industry, perhaps through the Natural Gas Reliability Council, should fully evaluate the recommendations of the FERC/DOE Deliverability Task Force and assist in the implementation of these recommendations as necessary.

Federal, state, and local officials should support the industry's efforts to address reliability and industry operating guideline issues that improve the overall quality of service to natural gas consumers.

- Address potential conflicts at federal and state levels between the regulatory framework and contracts, e.g. end-use curtailment, service obligations.

existing customers remember being curtailed years ago and this memory still affects their perceptions about the reliability of natural gas service. Historically, curtailment plans were devised to ensure that high-priority consumers, such as residential users, hospitals, and schools received natural gas during periods of shortage and physical emergencies (i.e., hurricanes or freeze-ups causing supply disruptions). Today, in stark contrast to the past, the gas on these interstate pipelines is owned by literally hundreds of shippers. Consequently, the industry should be aware of and address the potential conflict between allocation of natural gas supply on the basis of end use and a new system under Order 636A where natural gas is allocated on the basis of contract. These conflicts can exist at both the federal and state levels.

A similar inconsistency between regulatory framework and an industry based on contracts is the continuing service obligations of pipelines to provide sales service. The significance of both of these issues is being reduced through Order 636. However, the inconsistency may continue to exist in the future and may need to be addressed if only through an educational process.

In summary, this section addresses reliability and industry operating guidelines in the following areas:

- Operating procedures that can enhance reliability and make it easier for customers to arrange for natural gas service (examples: predetermined allocation procedures,[1] operational balancing agreements,[2] etc.)
- Pipeline operating procedures and information that allow the industry to respond to crisis and emergency situations, such as December 1989
- Areas where there may be conflicts or contradictions between the regulatory environment and contracts, e.g., curtailment plans based on end use and the continuing existence of pipeline service obligations.

The (C) **supply deliverability**, (D) **price volatility**, and (E) **marketing company** issues mentioned in the focus group analysis of reliability are beyond the scope of this section and are addressed elsewhere in the NPC study in Volume II, Source and Supply, and Chapter Ten of Volume I, the summary report.

The FERC/DOE Deliverability Task Force recently issued a report that addresses many of the areas listed above. The NPC has not tried to replicate or duplicate the extensive efforts of the FERC/DOE Deliverability Task Force. This is discussed more fully in Chapter Two of this report.

INDUSTRY EFFORTS TO IMPROVE RELIABILITY AND DEVELOP INDUSTRY OPERATING GUIDELINES

In Texas, the Voluntary Allocation Committee has been in existence for several years to help address reliability issues, particularly in times of emergency or crisis. This Committee, which is composed of representatives for both intrastate pipelines and large end users in the state of Texas, has been effective in helping to address reliability concerns during times of stress. This effort is discussed more fully in Chapter Nine, Reliability, of Volume I, the summary report.

To help address reliability operating concerns with the electric industry, INGAA has been making a very strong effort to improve communication with the electric industry. Most recently, representatives from the pipeline industry and the North American Electric Reliability Council met to discuss pipeline reliability issues as they affect electric generation. Electric generation issues are more fully discussed in the electric generation section of this chapter.

In response to the need for operating guidelines, the industry in 1987 created a committee whose charge was to evaluate the necessity of industry-wide guidelines and make recommendations for these guidelines where appropriate. This effort, led by the INGAA/COPAS Committee with the input of various pipelines, producers, LDCs, and marketers created a set of suggested voluntary guidelines to move the industry toward standardization. Under development for more than two years, these voluntary guidelines now present operating, administrative, and accounting alternatives that are responsive to the dramatic changes that have occurred in the natural gas business since the advent of open-access transportation and the restructuring of the industry brought about by changes in federal regulations. The primary benefit of the INGAA/COPAS guidelines is to improve the accuracy and timeliness of the flow of information needed to acquire and transport gas in an open-access environment. These guidelines continue to be revised as changes occur within the industry. Any changes are reviewed and approved by the Natural Gas Review Committee which is composed of representatives from INGAA, COPAS, and the American Gas Association.

[1] Predetermined allocation procedures allow suppliers to direct the pipelines on how to allocate volumes delivered at supply sources that may not exactly match the nominations made at that same source. These procedures avoid after the fact reallocation problems that create significant ongoing accounting problems. Proposals are currently being circulated in the industry that require that these predetermined allocations methodologies be communicated directly to the transporter prior to gas flowing.

[2] Operational balancing agreements between interconnecting pipelines can serve a similar purpose to predetermined allocation procedures. They allow interconnecting pipelines to determine how volumes will be allocated in advance of the actual flow. Operational balancing agreements can also help to reduce the accounting effort for both pipelines and their customers.

The INGAA/COPAS Committee has recommended that guidelines be implemented using Electronic Data Interchange to improve the timeliness of information availability. Standard formats, called GAS*FLOW, have been developed that will facilitate the computerized exchange of information as recommended by the guidelines. The GAS*FLOW users group, which includes representatives of all segments of the industry, was formed to promote and facilitate the implementation of these standards. In addition, many pipelines are improving and will continue to improve their ability to operate the system through the installation of real-time measurement.

The NPC expects that during the course of implementation of FERC Order 636A, many pipelines will develop procedures to enhance the efficiency and reliability of their services. Specific procedures that will assist in this area include predetermined allocation procedures, the development of operational balancing agreements, and cash-out procedures to address imbalances. In addition, many pipelines are improving and will continue to improve their ability to operate their systems through the installation of real-time measurement.

The Transmission and Storage Task Group supports the efforts described above, as well as other efforts made by individual companies to improve the quality of natural gas service. Also, the Transmission and Storage Task Group supports the recommendation made in Volume I, the summary report, that the industry consider developing a Natural Gas Reliability Council to address reliability concerns facing the natural gas industry in a comprehensive and coordinated manner.

In summary, the industry has been making a concerted effort to address reliability concerns and develop operating guidelines, although significant progress remains to be made.

FERC/DOE DELIVERABILITY TASK FORCE

This task force, chaired by FERC Commissioner Jerry Langdon, began its work shortly after the December 1989 stress situation. The final report was issued in September 1992. Chapter One of the report, which contains the background, conclusions, and recommendations from the report, is included as Appendix H of this report. The Deliverability Task Force made a comprehensive review of natural gas deliverability issues with the express purpose of achieving a vision of developing a system of natural gas data to meet the needs of tomorrow's markets.

The Deliverability Task Force made a series of very specific recommendations to improve deliverability data, which were broadly grouped into four categories:

- Standardization of information
- Review, development, and dissemination of data
- Implementation of electronic data recording and electronic data interchange
- Planning and coordination for peak periods and emergencies.

The report states that the cost to both the government and industry and consumers should be considered in making decisions to proceed with the recommendations. Also, the need to protect proprietary data must be respected and the data must be collected in a manner that encourages private sector flexibility and innovation. The NPC has reviewed the recommendations made in the report and generally agrees with the overall thrust of the recommendations, although the Council has not attempted to reach a consensus on each and every recommendation.

The NPC does specifically support the recommendation to "conduct a conceptual and feasibility study on the structure and formation of a national voluntary organization to operate in times of emergency or extreme conditions such as those that developed during December 1989," and believes that a Natural Gas Reliability Council would be an appropriate vehicle to implement such a structure. The NPC also recommends that the industry specifically address the recommendations of the FERC/DOE Natural Gas Deliverability Task Force Report as part of its deliberations in identifying the mission of the Natural Gas Reliability Council and assist in the implementation of these recommendations as necessary.

ROLE OF FEDERAL, STATE, AND LOCAL OFFICIALS

Federal, state, and local officials have an important role in supporting the natural gas industry by addressing reliability and operating guideline issues consistent with the broad study theme of "regulators need to let it work." The NPC believes that the appropriate role of government and regulators is to support the efforts of the industry to address these issues—intervening only when circumstances indicate that the industry is not taking appropriate action.

Chapter Seven

Access to Pipeline and Storage Capacity

Recommendations — Access to Pipeline and Storage Capacity

The natural gas industry needs to develop better methods to communicate to customers the availability of transmission and storage capacity.

State regulatory authorities need to evaluate, and direct, as appropriate, the unbundling of natural gas sales from transmission and storage services by local distribution companies (LDCs) and intrastate pipelines in order to further the general objectives of FERC Order 636, and to encourage the more effective marketing of natural gas services by LDCs.

The industry needs to encourage the creation and recognition of market hubs as mechanisms to promote better market access and improved reliability of natural gas services.

Based upon comments by focus group participants, some customers are not satisfied with the present methods for obtaining information concerning the availability of transmission and storage capacity. Some customers have found it difficult to determine what capacity exists, and when or where capacity is available for use. Some producers seeking opportunities to deliver small quantities of gas for vehicular refueling stations have found it difficult to obtain transmission capacity from pipeline transporters that would be consistent with the needs of that particular marketing application. Also, potential new end users have complained of being uncertain about distributors' willingness to provide firm deliveries from existing facilities, or to build new facilities to accommodate new loads. Some customers need firm transportation services for only part of the year, but perceive existing rates and charges as requiring them to purchase capacity on a continuous basis for the entire year. Finally, the natural gas industry has not yet benefited from the development of market centers or market hubs. The potential for developing market hubs provides opportunities for both increasing the efficiency of gas marketing, and increasing the reliability of particular services by effectively diversifying the availability of supplies.

DISCUSSION

One of the problems causing difficult access to adequate firm or interruptible transportation and storage capacity is evolving regulatory policies. Since rules concerning the obligations of pipelines and distributors to serve markets are changing, it is sometimes difficult to forecast the availability of capacity to serve particular markets with transmission and storage of supplies from particular locations. This circumstance is sometimes compounded by the user's uncertainty concerning exactly which supplies from which locations are desired, or exactly what service parameters are desired to be effective. Sometimes, new or additional firm transmission and storage capacity is offered, but customers may not want to commit to new capacity, at incremental costs, preferring access to interruptible capacity at lower rolled-in costs. Nationally, producers seeking to develop markets for vehicular natural gas have complained that pipelines do not want to handle small quantities of natural gas for refueling stations. Customers' unmet needs range from the uncertainty about distributors' commitments to construct new transmission capacity to the uncertainty about pipelines' willingness to provide for daily fluctuations in small loads like natural gas vehicle refueling stations.

Other customers' concerns discovered in customer surveys included concerns for reliability of transmission services, which apparently resulted from customers' preference for lower-priced interruptible services. Although customers preferred not to purchase more costly firm services, their perception was that the quality of interruptible services was not satisfactory.

Improved marketing and a faster transition to an open-access environment should improve this situation. Companies providing natural gas services need to communicate better with their customers regarding exactly what services are available under particular conditions.

FERC Order 636 provides for considerable progress in stabilizing regulatory uncertainty, which will enhance customers' abilities to make longer-term commitments. In addition to resolving issues concerning service obligations and fixing future firm service levels, the Order provides for capacity releasing programs that should allow available capacity to be more accessible. Also, the proposed electronic bulletin boards of pipeline companies should ensure that all customers have access to information concerning all but the shortest term capacity releases, as well as opportunities to bid for any desired released capacity. The capacity release programs and the associated electronic notice posting methods should provide customers with an effective "menu" from which to select services to satisfy their needs, as well as to offset reservation charges for capacity that may not be needed at all times.

Under Order 636, industrial end users will have opportunities to work toward long-term contracts with producers and marketers, and to obtain firm transportation services on pipelines. Those end users desiring firm contracts for deliveries to their "burnertips" may also need firm transportation contracts with LDCs. State regulators need to consider the needs of their end users, and direct, as appropriate, the unbundling of natural gas sales from transmission and storage services performed by LDCs. Without considering the possibility of unbundling of LDCs' services, it will remain uncertain whether all customers will be able to obtain access to the nation's transmission and storage system. In this regard, one state regulatory commissioner, in responding to survey questions, advocated more aggressive marketing efforts by LDCs, commenting that his commission receives inquiries most weeks from customers seeking assistance in obtaining natural gas services for their neighborhoods or businesses.

A recent study by the FERC's Office of Economic Policy, entitled *Importance of Market Centers* (see Appendix G), concluded that market centers or market hubs can be effective mechanisms to lower barriers to transmission and storage accessibility by providing ready reference points for information concerning natural gas services. Market hubs would naturally be located at major points of pipeline interconnections, near large sources of supplies, large storage facilities, or large markets. At these readily available and widely recognized reference locations, buyers and sellers would make arrangements to buy, sell, and trade natural gas and related services. In addition to adding variability to customers' options for gas supplies, market hubs should provide diverse opportunities for obtaining transmission and storage services, and should provide producers and marketers with diverse sales opportunities.

Increased economic marketing efficiency can be achieved through the development and use of market hubs. With more options and information readily available, it is possible that customers could select a set of supplies and services that would meet their needs while consuming the least necessary capacities, and thus, the least capital commitments. This should provide customers with better access to transmission and storage services at lower costs.

Market hubs, operating with existing pipelines, should lower barriers and reduce transaction costs by making more comparable information more readily available. It should be easier for customers using market hubs to avoid problems involving pipeline receipt and delivery points, since the customers would have more choices of pipelines, and the pipelines would have more opportunities to benefit from the customers' access to diverse supplies and marketers' services. The unbundling of gas sales from transmission and storage services seems naturally related to the development of market hubs, and the FERC has instructed pipelines not to inhibit the development of market hubs in its Order 636.

By encouraging the creation and development of market hubs, there should be increased opportunities and more flexibility for purchasers to obtain and use natural gas. With multiple supply, storage, and marketing options available at these reference points, there should be increasing confidence in the reliability of natural gas. In present circumstances, where aggregate deliverability exceeds aggregate market requirements most of the time, a system of market hubs should increase the actual reliability of natural gas services for most customers.

In summary, access to transmission and storage capacity will be improved by:

- Improved marketing and better communication with customers concerning the locations, timing, costs, and availability of transmission and storage services
- Appropriate evaluation and direction by state regulators concerning the unbundling of gas sales from transmission and storage services by LDCs
- The creation and development of market hubs.

Improved access to the transmission and storage system will contribute to better utilization of existing facilities, more economic development of new facilities, and an increasing use of natural gas.

CHAPTER EIGHT

ENVIRONMENTAL AND SAFETY OPPORTUNITIES AND CONSTRAINTS

Natural gas represents an environmentally desirable energy alternative, not only because of its inherently clean-burning properties, but also because it is delivered to consumers through a transportation system that is safe and environmentally superior to systems used to deliver energy alternatives such as coal, oil, and electricity. Duplicative and sometimes conflicting environmental regulation at federal, state, and local levels and complicated permitting constraints on new pipeline construction discourage increased natural gas use and, as a consequence, encourage the use of these other, less environmentally desirable, energy sources. Many of these regulatory constraints are procedural, not substantive, and do nothing to enhance safety or environmental protection. Streamlining construction regulations and the process for obtaining construction permits would enhance the ability of natural gas to compete with energy alternatives and, thereby, avoid unnecessary pollution of the environment through the inadvertent promotion of less environmentally desirable fuels.

ENVIRONMENTAL OVERVIEW

Natural gas is the cleanest-burning fossil fuel. The combustion of natural gas to produce energy results in the emission of almost no sulfur dioxide (SO_2) and significantly less carbon monoxide (CO), carbon dioxide (CO_2), volatile organic compounds (VOC), and particulate matter than coal or oil. All of these compounds have been identified as having negative environmental effects, and most are controlled under the Clean Air Act. In fact, natural gas is considered a desirable energy alternative for complying with the 1990 Amendments to the Clean Air Act because it produces less of these harmful emissions. A variety of Clean Air Act compliance strategies, such as gas co-firing, gas re-burn, natural gas fueled vehicles, and the strategic use of natural gas during periods of high ozone nonattainment, are based on the increased use of natural gas.

Natural gas is more than 90 percent methane. Loss of methane, a greenhouse gas, during the production and transportation of natural gas has been identified as a possible secondary contributor to global climate change. There are few reliable, objective data on the question of methane emissions. The Gas Research Institute has initiated an aggressive program with the U.S. Environmental Protection Agency to develop reasonable estimates of the leakage of methane during the production and transportation of natural gas. Based on data gathered to date, a total of about 1 percent of total gas production escapes into the atmosphere.[1] Natural gas operations account for only a small fraction of world methane emissions and ranks after the following other methane sources: natural wetlands, animals, biomass burning, rice paddies, landfills,

[1] Robert A. Lott (Gas Research Institute), *Methane Emissions from U.S. Natural Gas Operations*, Abstract presented at the Nordic Gas Technology Center's Conference on Natural Gas and the Environment, Copenhagen, September 1992.

Recommendations — Environment and Safety

A streamlined regulatory process would enhance the competitiveness of natural gas and, in turn, its desirable environmental effects. Many of the regulatory requirements are avoidably slow and redundant. The Transmission and Storage Task Group makes the following recommendations for eliminating wasteful procedural constraints on the industry without diluting substantive environmental protections. The natural gas industry should:

- Actively promote to regulators, environmental interest groups, and the general public the environmental and safety benefits of increased use of natural gas as an energy alternative.
- Actively promote to regulators, environmental interest groups, and the general public the environmental and safety benefits derived from a buried transportation system.
- Work with the Federal Energy Regulatory Commission and other federal, state, and local agencies to expedite the review and approval process for new pipeline projects without diluting substantive environmental protections.
- Aggressively promote and fund the development of emission control and retrofit technology for compressor prime movers, and more efficient, cleaner burning new prime movers, to meet increasingly stringent emissions requirements.

termites, methane hydrates, waste water, oceans and fresh waters, and coal.[2]

After construction, a natural gas pipeline leaves only nominal environmental surface impact. Restoration of natural vegetation commences soon after construction is completed. Done properly, ground cover is replaced and, if successful, complete recovery takes only one or two growing seasons. A mature, recovered right-of-way is maintained as an open area only enough to provide a means of access for inspection, maintenance, and repair of the pipeline.

Also in terms of visual impact, natural gas pipeline rights-of-way tend to be relatively small compared to electrical transmission rights-of-way or railroad rights-of-way. This is because the pipeline itself is small and does not require extensive support structure or lateral easements. Pipeline rights-of-way are also left largely unmarred by towers, wires, grading, railroad tracks, and similar artifacts associated with these other energy transportation systems.

The highest risk, highest impact, environmental activity regularly undertaken by the natural gas industry is new pipeline construction. However, almost all pipeline construction is subject to strict environmental regulation at the federal, state, and local levels. In addition, heightened awareness and growing sophistication on the part of pipeline companies and federal, state, and local regulatory officials, as well as improved construction practices and technology, have minimized the potential for, and the incidence of, environmental harm from construction.

For example, modern trenching practices and associated equipment require little room to operate. The pipeline construction zone can generally be limited to 40 to 50 feet on either side of the pipeline. Current technology and associated equipment also allow for a relatively short period of environmental disturbance in the construction area. Time elapsed from the commencement of trenching activities on a stretch of pipeline construction until the pipe is in the ground and covered can be as short as 5 days. In areas of standing or flowing water, the trench can be open for as few as 24 hours.

Improved construction technologies have also decreased the environmental impact of river and wetland crossings. The most significant advances have come in the form of directional drilling and borings beneath obstacles such as rivers, railroads, and highways. Although very expensive, one of the first options considered when making a river

[2] Gas Research Institute, *Global Climate Change: A Gas Industry Program on Global Climate Issues*, July, 1990.

crossing is directional drilling under the river and pulling the pipe through. By drilling below the river bottom, it is possible to complete the crossing without any disturbance of the river's ecosystem.

SAFETY OVERVIEW

Pipeline safety is the responsibility of the U.S. Department of Transportation (DOT). The DOT is responsible for assuring the safety of over 1.6 million miles of natural gas pipeline, including gathering, transmission, and distribution pipelines. Since 1970 pipeline operators have been required to notify DOT of reportable incidents, including leaks that involve significant property damage, injury, or death. Based on these reports, the DOT has concluded that natural gas pipelines are one of the safest modes of regulated transportation.

The DOT's safety mandate stems from the Natural Gas Pipeline Safety Act of 1968. The DOT sets minimum pipeline safety standards (18 CFR Part 192), administers a nationwide inspection and enforcement program, supports research, and provides continuous training programs for industry and regulatory personnel. The DOT implements its inspection and enforcement program primarily through cooperative agreements with state agencies. Although subject to minimum federal standards, individual states are free to impose more stringent requirements.

Pipeline design, construction, and operation and maintenance are all subject to DOT safety requirements. These requirements impose more stringent conditions where population density—the number and concentration of people located near the pipeline—increases. The DOT also requires pipeline operators to establish an emergency plan to minimize the hazards in the event of a gas pipeline emergency.

Historically, natural gas transmission and gathering facilities have experienced only about 1.3 service incidents per 1,000 miles of pipeline per year.[3] Both the industry and the DOT study accident reports to seek ways to improve pipeline safety. In two areas—outside forces and corrosion—significant improvements have been made.

Typically, more than half of all pipeline safety incidents are caused by outside forces. Most of these outside forces were caused by human error in the operation of equipment such as bulldozers and backhoes. As a result, pipeline operators have been required since 1982 to participate in "one call" public utility programs. The "one call" program is a service utilized by public utilities and some private companies (e.g., oil pipelines and cable television) to provide preconstruction information to contractor or other maintenance workers on the underground location of pipes, cables, and culverts.

It is also important to note that modern pipeline design, construction, and testing techniques have significantly reduced the incidence of pipeline failure. Pipelines installed after July 1971 are required to use both external protective coatings and cathodic protection to protect against external corrosion. This requirement has resulted in a significant reduction in corrosion-related failure rates when compared to those for unprotected or partially protected pipe.[4]

More recent data support these conclusions. Incidents of failure remain at low levels. For example, in 1991 only 71 incidents were reported. This equates to an incidence rate of only about 0.23 incidents per 1,000 miles of pipeline (per year).[5] On average, the data for 1985 through 1991 shows consistently low rates of service incident rates, with no pattern showing either an increase or decrease in service incidents reported.

Concern has been expressed about the aging of the pipeline system. In fact, pipeline systems are continuously being rehabilitated and modernized. On average, the data for 1985 through 1991 show consistently low rates of service incident rates, with no pattern showing

[3] For a summary and analysis of DOT pipeline safety reports see, e.g., D. J. Jones, G. S. Kramer, D. N. Gideon, and R. J. Eiber, 1986, *An Analysis of Reportable Incidents For Natural Gas Transportation and Gathering Lines 1970 through June 1984*. NG-18 Report No. 158, Pipeline Research Committee of the American Gas Association. 5,862 service incidents were reported during this period.

[4] The reduced frequency of incident for newer pipe may also be influenced by improved knowledge of their location and better surface marking.

[5] 71 incidents over an estimated 300,000 miles of transmission and gathering pipeline. These figures are not comparable to earlier figures because the reporting requirements were relaxed in 1984.

either an increase or decrease in service incidents reported. Considering that the industry has grown during that same period, it is reasonable to conclude that the natural gas pipeline system is not deteriorating from a safety standpoint. Because of safety related expenditures and better training, the system may be actually getting safer over time.

Minimal environmental or safety harm should result from an accidental release or leak of natural gas during transportation, whether on- or offshore. Gas has a narrow range of combustibility and is lighter than air. It will rise and dissipate quickly upon release. For these reasons, the risk of damage, whether to people, property, or the environment, from an accidental release or leak of natural gas, even in the case of natural gas vehicles, is low.

Continued improvements are possible in the future. New technologies have been developed to allow operators to test operating pipelines for corrosion and potential defects, and correct problems before they result in leaks. One technology currently in use involves the use of so-called "smart pigs"[6] to examine the inside of a pipeline.

CONSTRAINTS

The stringent requirements of the 1990 Clean Air Act Amendments to reduce ozone may be a significant deterrent to expanding the current pipeline system or constructing new pipelines. The Amendments modified the focus of ozone non-attainment strategies to incorporate NOx controls along with hydrocarbon controls. While the controls required at each facility will be driven by site-specific facts such as existing technology and local air quality, emission control requirements for existing facilities could range from moderate combustion moderation to advanced catalytic controls. New facilities may be subject to stringent offset requirements.

The effect of these requirements in some cases will be to increase the cost of pipeline operations and potentially inhibit pipeline expansion within and into some parts of the country.

[6] A "smart pig" is a devise that travels inside underground pipeline and detects signs of internal corrosion.

Existing regulatory requirements do not support the timely construction of new facilities. Regulatory and permitting delays frequently prevent pipelines from being market responsive. Environmental review and reporting requirements extend to unreasonable extremes the regulatory approval process for new construction. Additionally, filing of applications is problematic due to duplicative, and sometimes conflicting, filing requirements with numerous agencies.

The net result of these delays is a loss of competitiveness and responsiveness to customer needs by the natural gas industry. As a consequence, energy consumers are drawn to other energy sources that are less safe and less environmentally attractive than natural gas, but which require less time and effort to install. Energy consumers tend to choose the energy alternative that provides what they want, when they want it, and at the price they want. The entire regulatory process can create a market bias in favor of less environmentally desirable energy sources, thereby increasing risk and harm to the environment by discouraging the increased use of natural gas.

The St. Petersburg/Hillsborough Connector project in Tampa, Florida provides a good example of some of the regulatory challenges to constructing new pipeline. This 36-mile project required over 20 environmental permits (exclusive of construction permits) from more than 9 different regulatory agencies. Wetlands permits were particularly time-consuming to acquire because many wetland areas required multiple permits from multiple agencies.

Coordination among regulators of new construction review and approval could expedite the construction of new facilities without diluting substantive environmental protections. Formal agreements among state and federal regulators, "programmatic agreements," establishing coordinated or consolidated procedures for addressing common and overlapping environmental issues could streamline the review and approval process. These formal agreements could include conflict resolution procedures to expedite environmental appeal efforts. Such arrangements would reduce avoidable procedural delays, eliminate the risk of duplicative requirements, and provide a mechanism for addressing conflicting regulations.

CHAPTER NINE
SERVING ELECTRIC GENERATION LOADS

Recommendations — Electric Generation

The natural gas and power generating industries must cooperate, coordinate, and compromise to make this transporter/customer relationship work.

The natural gas industry must develop creative and tailored services to encourage flexibility and commitment to gas by the electric utilities.

The power generation industry participants in the focus group survey identified reliability of and the general lack of familiarity with natural gas operations as concerns. The reliability issue was covered in Chapter Six. This chapter will address the operational concerns in providing gas for power generation from the gas industry's perspective.

The greatest potential for growth in natural gas consumption is in the electric power generation industry. Forecasts predict the electric power industry could double its use of natural gas during this decade.[1] In NPC Reference Case 1 (the moderate energy growth scenario), total annual gas load projected to support the electrical sector of the market is projected to increase from 2.8 TCF in 1991 to 3.8 TCF by the year 2000, increasing to 5.0 TCF by 2010. However, to achieve this level of growth, the natural gas and electric power industries must play a critical and interdependent role in each other's future.

Each industry participant, including gas producers, interstate pipeline companies, local distribution companies, marketers, and electric utilities, has disparate perceptions on these issues. This section addresses the obstacles to increasing gas usage for power generation from the interstate and intrastate pipeline's perspective. In particular, the operational impact on the transporter's transmission and storage operation is discussed.

The electric power generation is seen by the gas industry as an attractive opportunity to increase its market share. However, to pipeline companies with little experience serving electrical loads, power generation requirements are viewed with concern as to the operating demands on the system. The characteristics of gas consumption that most affect the ability of the natural gas industry to supply electric loads are: (1) the daily and hourly fluctuations in electric load and corresponding gas load requirement; (2) the delivery pressure requirements to the power generator; and (3) the need for firm transportation or a reliable service.

These consumption characteristics are not new to the natural gas industry; other temperature-sensitive gas markets also exhibit fluctuations and can be difficult to predict. However, the major difference with gas requirements of

[1] Electric Power Research Institute, *Natural Gas for Electric Power Generation: Strategic Issues, Risks, and Opportunities*, 1990.

electric utilities is the relative size of the gas load for individual units (especially peaking units) and the short duration in which the gas is required. Natural gas requirement for gas-fired electric utility units are very large and isolated compared to the average residential, commercial, or industrial gas loads, which are broadly distributed over the system. Only the load requirements of the largest industrial and cogeneration customers compare to that of electric utilities.

The industry's ability to reliably serve the power generation market is directly related to the type of generating capacity proposed (i.e., base load or dispatchable). However, a number of concerns arise in the case of power generation designed for low load factor dispatchable peaking demands. To better understand these concerns, the service requirements of the electric utility and the capabilities of the system must be reviewed.

From the **electric generators perspective**, a typical peaking unit providing summer peak day power demands will be off line until midday, come on-line within 15 to 20 minutes without notice and requiring up to 100 percent of its natural gas supply for a 1 to 12 hour duration and then be off-line for the rest of the day. The no-notice delivery requirement is a function of the generators inability to predict when the power unit will be dispatched. This unpredictability may repeat itself throughout the cooling/summer season, and to a lesser extent occur during the heating season. For some peaking generators, the total annual hours of operation may total 500 hours or less, equating to a mere 6 percent annual load factor. In addition, a typical peaking unit may require a minimum delivery pressure of 300 to 350 psig, in comparison to the typical 50 to 250 psig minimum delivery pressures provided by the gas industry.

Tailored services are complicated because of the low and unpredictable nature of the load factor of the peaking plant. The preferred firm transportation service and corresponding demand charges can be uneconomical. Use of interruptible transportation service can improve the economics, but is considerably less reliable. Firm supply arrangements are complicated by the unpredictable low utilization and large daily demands, often forcing the plant to contract for interruptible supply. Storage could be used to provide firm gas supply. However, traditional storage fields (depleted oil and gas fields) often require a minimum number of days of service and a significant volume to provide the desired peak-day deliverability. Salt dome storage is more responsive, but more expensive than traditional storage. Storage may not be an option in some downstream markets where substantial increments of new turbine capacity are being installed.

From the **pipeline/LDC perspective**, a variety of operational conditions must be satisfied in order to provide service of this flexible nature. The potential problems occurring during the start-up of a large turbine power unit must be analyzed to ensure the integrity of a pipeline system that was originally developed under greatly different operating conditions. Traditional firm and interruptible transportation services often require a notification period of typically 24 to 48 hours prior to the commencement of deliveries. Deliveries are to be made on a even basis over the 24-hour period. Most interstate pipelines also have a system-wide minimum delivery pressure (ex. 50 to 250 psig) within their tariffs, often below the requested minimum of the power generator. The purpose of minimum pressure requirements on a pipeline system acts as a design criteria in protecting deliveries to customers at remote areas of the pipeline, without maintaining uneconomically high pressures throughout the system. Delivery pressures generally exceed the design minimums on the main trunks of the pipeline system but can not be guaranteed without the addition of facilities. Current industry operating procedures are not suited to the swing nature of the gas-powered units and can have a significant economic impact.

Technology is assisting in bringing these industries together. Manufacturers of turbine units for power generation are in the process of developing a unit that is capable of operating at lower inlet pressures, thereby eliminating the redesign of pipelines to accommodate the pressure requirements. Also, affordable and reliable PC-based transient simulation models are being developed that can be utilized by the pipelines to better understand the effects of the power units coming on-line.

COORDINATION REQUIREMENTS[2]

To develop services that addresses both industries' needs, close coordination among all industry participants is required. Since solutions to electric-gas coordination problems are unique to each utility and gas pipeline, electric utilities and their gas pipelines will have to work together to effectively deal with their unique problems.

The coordination of gas supply and gas-fired generation is important in three areas: planning of new capacity, planning of daily and hourly capacity, and contractual arrangements. New capacity should be planned to prevent operating difficulties and minimize any additional costs through siting, back-up fuel arrangements, choice of pressure, and gas transportation and storage arrangements. Reliable and economical operation can be achieved through timely communication of load forecasts and changes in planned generation, along with real-time monitoring of utility operations.

The key to successful collaboration between the industries is how well each understands the other's operation criteria and how well each can integrate those requirements into their own operating decisions to the benefit of both. As demonstrated by the successful operation of gas-fired electric utilities in experienced regions such as ERCOT (Electric Reliability Council of Texas), the goal of coordination and integration of operations can be both achievable and economically viable. Electrical utilities and gas pipelines new to gas-fired power generation should learn from the experienced utilities, as well as develop innovative approaches to coordinating generation and gas supply.

This collaboration has been increasingly occurring among individual gas companies and electric utilities. The recently released Electric Power Research Institute report *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Correlation* directly addresses this issue. Also, representatives from the Interstate Natural Gas Association of America and the North American Electric Reliability Council recently met to discuss reliability issues. These efforts will need to continue if the industries are to make this important relationship work in the future.

CONCLUSION

The electric utility and natural gas industries stand to gain significantly from common efforts to ensure reliable gas supplies for existing and planned power generation. The issues addressed in this report need not deter electric utilities and gas pipelines from planning increased gas reliance either to meet the growing demand for electricity or to achieve cost-effective environmental compliance. These issues must be resolved, however, if the interdependent relationship between the two industries is to develop smoothly and successfully in growing downstream markets. The coordination problems addressed in this report have developed because the electric and natural gas industries have matured largely independent of, and without reliance on each other. There are major coordination needs for effective interaction between both industries. There is a need to exchange load forecast on a timely and frequent basis to avoid misunderstandings. This is especially true because of the transient effects on the pipeline systems caused by the start-up of the large gas turbines. The natural gas and power generating industries must cooperate, coordinate, and compromise to make this transporter/customer relationship work. The gas industry must develop creative and tailored services to encourage flexibility and commitment to gas by the electric utilities.

2 Electric Power Research Institute, *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination*, Research Project 3201, September 1992.

Chapter Ten
Gathering Systems

Recommendation — Gathering Systems

Gathering systems are a critical link in aggregating natural gas from the wellhead, providing processing and treating services, and delivering merchantable natural gas to intra- and interstate pipelines. Unbundling of gathering systems as a result of FERC Order 636 has focused attention on the potential impact on rates for gathering on individual gathering systems that were previously subject to "rolled-in" treatment. Stability in gathering fees for producers and consumers and acceptable economic returns for gathering systems owners will best be accomplished by unbundling, open access, and market forces. Oversight at the state level may be indicated in isolated cases; but regulation is not an acceptable alternative for the industry where sufficient competition exists.

One of the issues of unbundling under FERC Order 636 is the impact on gathering systems and the rates charged for gathering natural gas prior to its delivery to a pipeline transmission system.

Interstate pipelines that own gathering systems are concerned that they receive acceptable rates of returns for these specialized production area facilities; and may be in the process of mandated restructuring under Order 636 or divesting them to unregulated parties.

Historical gathering rates on an interstate system may have been understated because of "rolled-in" treatment and may reflect a low net book value. Once a sale or transfer of such facilities to an unregulated party occurs, the possibility exists that gathering costs may be adjusted to reflect an incremental increase in direct costs of operations and acquisition costs in excess of historical book value. A second possibility of increased gathering fees occurs if production area facilities retained by the pipeline are unbundled and separate fees are charged under Order 636.

A concern during the Order 636 transition for the industry is that re-regulation does not occur for gathering systems as a reaction to increases in gathering rates. The producing community is concerned that incremental adjustment in gathering rates do not negatively affect netbacks to existing production, or to new exploration or development projects. Additionally, LDCs and end users are concerned that they cannot pay gathering rates that are too high relative to competitive standards, or rates that are too high to maintain and expand markets. At the same time, companies that own, acquire, or expand gathering systems expect an acceptable rate of return reflected in competitive gathering charges that may have been previously masked by "rolled-in" treatment.

WHAT IS A GATHERING SYSTEM

Gathering systems are unique to production areas and are the supply sources for inter- and intrastate pipelines. They can be the direct connection to producing wells, and can be from a few feet in length to a single well, or become large volume integrated systems of thousands of wells and over a thousand miles of pipe to supply one or more gas processing plants. A gathering system can equal a large LDC pipeline in complexity and an interstate high pressure pipeline in volumes, pressure, and compression horsepower. The unique aspect of a gathering pipeline versus other pipelines is that the gas is probably yet to be processed or treated to finished product specifications that can meet most end users' requirements. There are some cases, however, where wellhead natural gas closely meets final pipeline specifications.

Besides aggregation, gathering systems may provide additional required facilities in order to make the gas "merchantable" and meet pipeline specifications as to BTU and quality content. These services require additional investment in equipment that will cause the gas to be merchantable:

- ***Dehydration*** – Free water is "knocked out" and moisture content is reduced.
- ***Treatment*** – Removal of contaminants such as hydrogen sulfide (H_2S) or nitrogen.
- ***Processing*** – Separating gas liquids (such as propane, butane, ethane, natural gasoline) for further fractionation and thereby reducing gas BTU content.
- ***Compression*** – Providing compression to aggregate and inject the gas into pipeline systems.

There are other variables for a gathering system that influence costs and fees. These include the production volume and reserves of the gas well, field development or growth possibilities, the well and pipeline pressures, the distance to the nearest pipeline, and pipeline capacity.

Owners of gathering systems can be the producer or independent well owner, stand alone gathering companies who will build the facility for an acceptable fee and return, multipurpose companies such as marketers who may build such systems for aggregation purposes, and finally pipelines to ensure supply and to commit gas reserves to being transported through their pipeline. Each will have different business and financial incentives for building the system.

TODAY'S ISSUES

Gathering systems that are currently part of a regulated interstate pipeline are the primary focus of concern for all industry parties—producers, marketers, gathering companies, pipelines, consumers, and regulators—state (utility and oil and gas commissions) as well as the FERC at the federal level.

The problem is that gathering system costs were often previously rolled into merchant service rates, and the resulting gathering fee was only a portion of the total operating cost, capital costs, and recovery, as a result of spreading the costs over several rates and services. The sale or divestiture, or unbundling of a gathering system as related to FERC Order 636 restructuring can cause the gathering rates for individual gathering systems to be radically adjusted.

The FERC has indicated a strong preference that production area rates be separately charged. Unless special provision is made for the recovery of a portion of the costs of owning and operating individual facilities (gathering systems), one of three things may occur:

1. It may be impossible for the pipeline to recover the full cost of the facility without having the opportunity to roll costs into merchant services
2. The resulting reduction in netbacks to producers may cause them to shut in production or to reduce further development of the affected reserves
3. The pipeline will divest the property to unregulated parties, and cause the gathering charges to be adjusted as the new owner attempts to recover the operating and capital costs that cannot be allocated to other customers.

A substantial portion of gathering systems are unregulated and owned by private or unregulated companies. A similar possibility exists, that private unregulated carriers can "unilaterally" increase gathering rates as a result of being the sole purchaser, or require unusually higher rates of returns for systems purchased from interstates as they restructure the gathering system line of business. This can become a state regulatory problem for either of two commissions: a State Public Utilities Commission or a State Oil and Gas Commission.

The legal basis for the regulation of gathering system is clouded. Section 1(b) of the Natural Gas Act exempts "production and gathering" from the scope of federal regulation by the FERC. However, the case law supports FERC regulation of gathering performed in connection with interstate pipeline transportation.

State Regulatory Commissions are being petitioned to regulate gathering costs both for properties divested by interstates and for existing systems that are privately held. Such regulation could involve oversight and review for rate adjustments on new, existing, or transferred "non-rate based gathering systems," and for wells that are connected to a single system, where an incremental connection is not economically justified and a "monopoly" gathering potential exists. If local community concerns oppose multiple pipelines, a competitive situation may be precluded by concerns totally beyond the realm of producers and gatherer's business relationships. Gathering system operators could be placed in a monopoly position even though it was not their purpose. Also, if "waste" is occurring due to gas not being produced as a result of gathering policies, a state commission could be requested to intervene.

Such regulation may be appropriate and necessary where single gathering systems are in place and thus no competition exists. However, where competition exists for gathering services, market forces and contractual relationships should replace state regulation. Where regulatory oversight is indicated due to the absence of competitive forces, State Commissions should focus on actual operating costs, book values at fully depreciated costs and the actual purchase price. Analysis should additionally include volumes for throughput to be based on the higher of actual throughput, practicable throughput, or system design capacity and capped rates of return. The question of how much choice is available to producers and shippers on a gathering system could lead a commission to different regulatory strategies. A gathering operator encouraging "open-access" buying and trading could provide options and choices to its customers and thereby discourage producers or others from requesting regulatory oversight or planning. The gatherer could choose to be flexible and adopt more roles or combinations of roles such as producer, gatherer, aggregator, and marketer.

IMPACTS

The impacts of incremental increases in gathering charges are higher delivery costs of gas to the end user and a reduction to wellhead netback prices for drilling, development, and the production of natural gas. These increases may be necessary to assure continued operations and provide financial incentives for the gathering system owner.

If gathering costs are incrementally adjusted, then future drilling economics can be negatively impacted, and the expected net wellhead price will be reduced and marginal projects will be eliminated. At the same time, existing marginal production could be shut in as a result of increases in existing gathering fees. Similar reductions in gas markets will occur if LDCs cannot justify higher rates and end users cannot justify projects with higher costs.

RECOMMENDATION

One of the basic premises of FERC Order 636 is that an unbundling of the interstate system will allow "free-market forces" to level inequities and allocate costs and revenues to more nearly reflect the cost of business and direct capital to areas of opportunity.

One possible solution if rates on some gathering systems are incrementally adjusted is to permit State Regulatory Commissions to take an approach as was done for storage and transportation facilities:

- Identification of gathering costs that are to be recovered through a special mechanism
- Determination of the mechanism to be used for the recovery of the costs
- Review of acceptable rates of returns for gathering costs and investments
- Identification of choices that are present and level of competition that exists.

Unbundling of gathering systems as a result of FERC Order 636 has focused attention on the potential impact on rates for gathering on individual gathering systems that were previously subject to "rolled-in" treatment. Stability in gathering fees for producers and consumers and acceptable economic returns for gathering systems owners will best be accomplished by unbundling, open access, and market forces. Oversight at the state level may be indicated in isolated cases; but regulation is not an acceptable alternative for the industry where sufficient competition exists.

Chapter Eleven

Transmission and Storage Technology

Recommendations — Technology

The gas industry should continue to support the development and deployment of new technologies to meet the needs of the gas transmission and storage industry and its customers.

The gas industry should work with regulators to create mechanisms, such as incentive regulation, to ensure that the benefits of new technology development accrue to those who assume the risks and bear the costs (as discussed in the Technology chapter of Volume I, the summary report).

The purpose of this section is to identify the technology issues facing the transmission and storage segment of the gas industry, and describe how current research and development (R&D) addresses those needs.

The NPC study envisions an expanded natural gas industry that will accommodate increased customer demand, primarily utilizing existing and currently planned facilities. At the same time, the NPC envisions a gas transmission and storage system that continues to work efficiently, reliably, safely, and in an environmentally acceptable manner while accommodating the changes inherent in FERC Order 636, as well as implementation of the Clean Air Act Amendments and future environmental regulation. In making the transition to a gas transport system that can achieve the gas industry's goals, technology will play an increasingly important role.

How new technology development is funded and the regulatory treatment of R&D-related expenses is a problem facing the gas industry in total and is discussed in the Technology section of Volume I, the summary report. Incentive regulation for the pipeline industry is discussed at the beginning of this chapter. There is a fundamental premise that for each company to obtain the full benefits of technology development, a risk-reward mechanism must be established with the regulatory community, so that there is adequate incentive to develop and adopt new technologies.

While the focus group participants made no specific reference to transmission and storage technology, many of the transmission issues that were identified are influenced by technology. Maintaining or improving system reliability, becoming more market driven, improving commitment to technology commercialization, and creating incentives were mentioned as important concerns.

To achieve the goals set forth in this study, the gas transmission and storage industry will need to more efficiently generate and manage information about system operations to improve system efficiency, reliability, and response to customer needs. The integrity and reliability of the industry's pipeline and storage assets must be maintained, and the capabilities of the system must be efficiently enhanced to ensure timely service to new customers.

Developing more effective solutions to environmental compliance requirements will be an increasingly important industry need as well.

OVERVIEW OF TRANSMISSION AND STORAGE R&D IN THE GAS INDUSTRY

The gas industry has a 1992 R&D budget of $24 million allocated to develop information and new technologies to meet the needs of the transmission and storage system. Two-thirds of that budget ($17 million) is managed by the Gas Research Institute (GRI). The Pipeline Research Committee of the American Gas Association conducts a $4 million research program; while manufacturers contribute $2 million, and the industry $1 million. The research activities are closely coordinated among the groups and many programs are jointly funded. The gas industry's R&D plans benefit from the input of advisory groups and supervisory committees that represent members of the transmission and storage industry at various levels.

The broader issue of how the industry conducts R&D and how it is funded is discussed in the Technology chapter of Volume I, the summary report. The needs of the transmission and storage technology segment of the industry and the R&D currently underway to address those needs are discussed below.

TRANSMISSION TECHNOLOGY—STRATEGIC ISSUES AND OBJECTIVES

While selected gas industry R&D projects target cost reductions in new construction, most of the gas transmission industry's R&D effort is directed at the following objectives:

- Reducing transportation costs
- Assuring deliverability of natural gas to customers
- Enhancing transport system reliability
- Maintaining the integrity of the gas transport system
- Reducing compressor station emissions and minimizing the cost of compliance
- Operating and maintaining the gas transport system; and constructing new facilities in a safe and environmentally desirable manner.

Specific R&D thrusts are in the areas of pipeline prime mover emissions reduction and compressor station efficiency improvement, automation systems, transport measurement technology, transmission piping systems, sensors and controls, and storage technology. This includes basic research in areas such as fundamental pipeline materials, gas flow fluid mechanics, and combustion chemistry. The gas transmission industry has also, through GRI, begun operation of a metering research facility, and a non-destructive evaluation research facility is under construction.

COMPRESSOR EMISSIONS

As is discussed in the environmental sections of this study, the gas industry is attempting to expand during a time of growing environmental constraints on the industry. The Clean Air Act Amendments, passed in November 1990, set in motion a process to improve environmental quality by controlling a broad range of pollutants. Many of the areas targeted for regulation are important for the gas transmission and storage industry. Title I of the Clean Air Act Amendments deals with ozone control by defining a set of requirements for controlling NOx from pipeline compressor engines.

A key objective of R&D programs for the gas transmission industry is to develop cost-effective technologies for meeting emission control requirements. GRI is currently working with all of the major suppliers of pipeline compressor engines (turbines and reciprocating engines) to develop both retrofit and new equipment that will meet the NOx requirements. Many of these retrofit kits will be field tested at pipeline companies to demonstrate their performance in the field. The American Gas Association's Pipeline Research Committee and GRI are involved in a joint assessment to characterize future compressor station requirements and identify emerging technologies worthy of development. GRI and the Pipeline Research Committee are also planning to initiate work to support the use of alternative techniques to the extremely costly and burdensome continuous emissions monitoring equipment that is being mandated.

COMPRESSOR OPERATIONS

A large portion of the total cost of transporting and storing gas is operating and maintaining compressors. Improved compressor operating efficiency is an objective for R&D in the areas of improved instrumentation and measurement of operating conditions. Diagnostic software for optimizing compressor operations and maintenance is currently being tested on industry compressors driven by both turbines and reciprocating engines. Compressor noise management and station design are also issues that are being researched.

TRANSMISSION AUTOMATION SYSTEMS

In the last two decades, gas transmission companies have made significant investments in computer hardware and software to develop Supervisory Control and Data Acquisition (SCADA) systems. Today's operational environment reflects the need for a more global approach to automation emphasizing real-time pipeline monitoring, control, and communications to optimize pipeline operation and make it responsive to customer needs.

As integration of field data acquisition with other company functions such as customer billing is completed, creating an integrated system where a customer can obtain consistent information about transportation options becomes a priority. The INGAA/COPAS effort to describe the nature of information flow between companies and create a uniform nomenclature is a step in this direction.

TRANSMISSION MEASUREMENT TECHNOLOGY

Efficiently transporting natural gas requires accurate measurement of large quantities of flowing gas, particularly in an open-access transportation environment. R&D is being conducted to improve overall volumetric and energy-measurement accuracy by developing improved meters, installation configurations, and flow conditioning devices, and to develop more accurate analytical procedures for gas measurement that capitalize on advances in fluid mechanics, thermodynamics, chemical engineering, and electronics.

The Meter Research Facility now in operation at the Southwest Research Institute in San Antonio, Texas, is used as a controlled testing environment to simulate actual pipeline gas flow conditions.

PIPELINE INSPECTION AND MAINTENANCE

Maintaining the pipeline and storage asset to achieve reliable and safe transportation services requires a more thorough understanding of pipe conditions. This can be achieved by improving the capabilities of inspection technology and the interpretation of their signals. The gas industry is currently constructing a facility to simulate actual pipeline conditions for use in evaluating and developing advanced Non Destructive Evaluation (NDE) equipment and methods to detect and characterize flaws that are characteristic of metal transmission piping. The goal of the industry is to detect and characterize steel pipe anomalies through the greater accuracy and discrimination than afforded by state of the art equipment. The Pipeline Simulation Facility, located at Battelle Columbus Laboratories in Columbus, Ohio, is comprised of an NDE laboratory, a non-pressurized pull-through facility (Pull Rig), and a pressurized flow loop which simulates a transmission pipeline in service.

Both the Pipeline Research Committee and GRI manage a coordinated R&D that is trying to improve ways of inspecting and testing pipelines. New and innovative methods to measure pipeline conditions are also being evaluated and tested.

PIPELINE TECHNOLOGIES

New and lower-cost gas transmission piping and materials for new construction, repair, and pipe upgrade systems that are more resistant to damage caused by corrosion and crack propagation would reduce pipeline company's installation and maintenance expenses. Current R&D programs focus on line pipe, materials, corrosion, welding, coatings, and installation, repair, and rehabilitation techniques.

UNDERGROUND STORAGE

Record storage withdrawals played a critical role in ensuring deliveries when the natural gas system was severely tested during the cold weather of December 1989. Maintaining and enhancing the deliverability of existing storage facilities is the primary focus of R&D in this area. A secondary focus is on technologies to reduce the costs of underground storage operations.

Storage reservoir performance R&D primarily emphasizes enhancing well productivity and optimizing the operation of storage facilities. A set of guidelines on storage well productivity enhancement will be produced that represents a consolidation of industry knowledge in this area. Deliverability of natural gas from underground storage facilities will be maximized through integration of all subsurface operations. Reservoir simulation models are currently being used by many storage operators, and the development of integrated versions is underway.

APPENDICES

The Secretary of Energy
Washington, DC 20585

June 25, 1990

Mr. Lodwrick M. Cook
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear ~~Mr. Cook~~ Lod:

Through this transmittal, I am formally requesting that the National Petroleum Council (NPC) perform two studies that are currently of critical interest to the Department of Energy. These studies are described below.

Constraints to Expanding Natural Gas Production, Distribution and Use

I request that the NPC conduct a comprehensive analysis of the potential for natural gas to make a larger contribution, not only to our Nation's energy supply, but also to the President's environmental goals. The study should consider technical, economic and regulatory constraints to expanding production, distribution and the use of natural gas. In the conduct of this study, I would like you to consider carefully the location, magnitude and economics of natural gas reserves, and the projected undiscovered and unconventional resource; the size, kind and location of future markets; the outlook for natural gas imports and exports; and potential barriers that could impede the deliverability of gas to the most economic, efficient and environmentally sound end-uses.

This study comes at a critical time, given the increased interest in natural gas, for developing public and private sector confidence that natural gas can make a greater contribution to the energy security and environmental enhancement of our Nation. I anticipate that the results of your work will be able to contribute significantly to the development of the Department's policies and programs.

The U.S. Refinery Sector in the 1990's

U.S. refineries face significant changes to processing facilities in the next decade, particularly in response to new environmental legislation that will affect emissions and waste disposal from refineries and the composition of motor fuels. Substantial investments are likely to be required to comply with proposed Clean Air Act Amendments, including provisions dealing with air toxics and alternative fuels. There is concern about the U.S. engineering and construction industry's capability to design, manufacture, and install quickly the large number of new, sophisticated processing facilities that would be necessary to supply these fuels.

Product imports, which are projected to increase, may also have to be treated differently than in the past. For example, if U.S. refiners have different gasoline specifications (e.g., Reid Vapor Pressure, aromatics, olefins, oxygen content) than foreign refineries, imported products may require additional U.S. refining.

I request that the NPC assess the effects of these changing conditions on the U.S. refining industry, the ability of that industry to respond to these changes in a timely manner, regulatory and other factors that impede the construction of new capacity, and the potential economic impacts of this response on American consumers.

I look forward to receiving your results from these two studies and would like to be notified of your progress periodically.

Sincerely,

Jim

James D. Watkins
Admiral, U.S. Navy (Retired)

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. This request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary of Energy include:

- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil & Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986)
- *Factors Affecting U.S. Oil & Gas Outlook* (1987)
- *Integrating R&D Efforts* (1988)
- *Petroleum Storage & Transportation* (1989)
- *Industry Assistance to Government* (1991)
- *Short-Term Petroleum Outlook* (1991)
- *Petroleum Refining in the 1990s–Meeting the Challenges of the Clean Air Act* (1991).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

NATIONAL PETROLEUM COUNCIL

MEMBERSHIP

1992

William L. Adams
Chairman and Chief Executive Officer
Union Pacific Resources Company

Charles W. Alcorn, Jr.
President
Alcorn Production Company

Jack M. Allen
Chairman of the Board
Alpar Resources, Inc.

Robert J. Allison, Jr.
Chairman and Chief Executive Officer
Anadarko Petroleum Corporation

Eugene L. Ames, Jr.
President
Venus Oil Company

Robert O. Anderson
President
Hondo Oil & Gas Company

Ernest Angelo, Jr.
Petroleum Engineer
Midland, Texas

Philip F. Anschutz
President
The Anschutz Corporation

John B. Ashmun
Chairman of the Board
Wainoco Oil Corporation

Ralph E. Bailey
Chairman of the Board and
Chief Executive Officer
United Meridian Corporation

D. Euan Baird
Chairman, President and
Chief Executive Officer
Schlumberger Limited

William W. Ballard
President
Ballard and Associates, Inc.

Victor G. Beghini
President
Marathon Oil Company

Jack S. Blanton
President and Chief Executive Officer
Eddy Refining Company

John F. Bookout
Former President and
Chief Executive Officer
Shell Oil Company

Donald R. Brinkley
President and Chief Executive Officer
Colonial Pipeline Company

Frank M. Burke, Jr.
Chairman and Chief Executive Officer
Burke, Mayborn Company, Ltd.

Michael D. Burke
President and Chief Executive Officer
Tesoro Petroleum Corporation

Bruce Calder
President
Bruce Calder, Inc.

Robert H. Campbell
President and Chief Executive Officer
Sun Company, Inc.

Scott L. Campbell
Partner
Washington Policy and Analysis

William E. Carl
President
Carl Oil & Gas Co.

NATIONAL PETROLEUM COUNCIL

R. D. Cash
Chairman, President and
Chief Executive Officer
Questar Corporation

Collis P. Chandler, Jr.
President
Chandler & Associates, Inc.

Rodney F. Chase
President and Chief Executive Officer
BP America Inc.

Neil D. Chrisman
Managing Director
Morgan Guaranty Trust Company
of New York

Danny H. Conklin
Partner
Philcon Development Co.

Lodwrick M. Cook
Chairman of the Board and
Chief Executive Officer
Atlantic Richfield Company

Milton Copulos
President
National Defense Council Foundation

Edwin L. Cox
Chairman
Cox Oil & Gas, Inc.

John H. Croom
Chairman, President and
Chief Executive Officer
The Columbia Gas System, Inc.

Thomas H. Cruikshank
Chairman of the Board and
Chief Executive Officer
Halliburton Company

Keys A. Curry, Jr.
Executive Vice President
Destec Energy, Inc.

George A. Davidson, Jr.
Chairman of the Board and
Chief Executive Officer
Consolidated Natural Gas Company

Kenneth T. Derr
Chairman of the Board and
Chief Executive Officer
Chevron Corporation

John P. DesBarres
President and Chief Executive Officer
Transco Energy Company

Cortlandt S. Dietler
Chairman and Chief Executive Officer
Associated Natural Gas Corporation

David F. Dorn
Co-Chairman of the Board
Forest Oil Corporation

James W. Emison
President
Western Petroleum Company

Ronald A. Erickson
Chairman of the Executive Committee
Erickson Petroleum Corporation

Fred H. Evans
President
Equity Oil Company

Richard D. Farman
Chairman and Chief Executive Officer
Southern California Gas Company

J. Michael Farrell
Partner
Manatt, Phelps & Phillips

William L. Fisher
Director
Bureau of Economic Geology
University of Texas at Austin

Charles R. Ford
State Senator
Tulsa, Oklahoma

Joe B. Foster
Chairman
Newfield Exploration Company

H. Laurance Fuller
Chairman, President and
Chief Executive Officer
Amoco Corporation

James F. Gary
International Business and Energy Advisor
Honolulu, Hawaii

James A. Gibbs
President
Five States Energy Company

James J. Glasser
Chairman and President
GATX Corporation

F. D. Gottwald, Jr.
Chairman of the Board,
Chief Executive Officer and
Chairman of the Executive Committee
Ethyl Corporation

John J. Graham
President and Chief Executive Officer
Graham Resources Inc.

David G. Griffin
Owner/President
Griffin Petroleum Company

David N. Griffiths
Senior Vice President, Administration
Citizens Gas and Coke Utility

Fred R. Grote
Chairman of the Board and
Chief Executive Officer
DeGolyer and MacNaughton

Robert D. Gunn
Chairman of the Board
Gunn Oil Company

Ron W. Haddock
President and Chief Executive Officer
FINA, Inc.

Michel T. Halbouty
Chairman of the Board and
Chief Executive Officer
Michel T. Halbouty Energy Co.

Andrew J. Hall
Chairman, President and
Chief Executive Officer
Phibro Energy, Inc.

John R. Hall
Chairman and Chief Executive Officer
Ashland Oil, Inc.

Ronald E. Hall
President and Chief Executive Officer
CITGO Petroleum Corporation

Frederic C. Hamilton
Chairman, President and
Chief Executive Officer
Hamilton Oil Company, Inc.

John P. Harbin
Chairman of the Board, President
and Chief Executive Officer
Lone Star Technologies, Inc.

Robert P. Hauptfuhrer
Chairman and Chief Executive Officer
Oryx Energy Company

Raymond H. Hefner, Jr.
Chairman and Chief Executive Officer
Bonray Drilling Corporation

Donald J. Heim
Chairman and Chief Executive Officer
Washington Gas Light Company

Frank O. Heintz
Chairman
Maryland Public Service Commission

Roger R. Hemminghaus
Chairman and Chief Executive Officer
Diamond Shamrock, Inc.

Dennis R. Hendrix
Chairman, President and
Chief Executive Officer
Panhandle Eastern Corporation

Leon Hess
Chairman of the Board and
Chief Executive Officer
Amerada Hess Corporation

C. Paul Hilliard
President/Owner
Badger Oil Corporation

H. T. Hilliard
Director
Hallador Petroleum Company

Robert B. Holt
Independent Oil and Gas Producer
Midland, Texas

Robert E. Howson
Chairman of the Board and
Chief Executive Officer
McDermott International, Inc.

The Honorable
Roy M. Huffington
American Ambassador to Austria

Ray L. Hunt
Chairman of the Board
Hunt Oil Company

Joseph T. Hydok
Executive Vice President, Gas Operations
Consolidated Edison Company
of New York, Inc.

Ray R. Irani
Chairman, President and
Chief Executive Officer
Occidental Petroleum Corporation

A. Clark Johnson
Chairman and Chief Executive Officer
Union Texas Petroleum Corporation

A. V. Jones, Jr.
Partner
Jones Company, Ltd.

Jon Rex Jones
Partner
Jones Company, Ltd.

Bernard J. Kennedy
Chairman, President and
Chief Executive Officer
National Fuel Gas Company

James W. Kinnear
President and Chief Executive Officer
Texaco Inc.

Charles G. Koch
Chairman and Chief Executive Officer
Koch Industries, Inc.

Ronald L. Kuehn, Jr.
Chairman, President and
Chief Executive Officer
Sonat Inc.

Kenneth L. Lay
Chairman and Chief Executive Officer
Enron Corp.

William I. Lee
Chairman of the Board and
Chief Executive Officer
Triton Energy Corporation

John H. Lichtblau
Chairman and Chief Executive Officer
Petroleum Industry Research
Foundation, Inc.

William C. McCord
Chairman and Chief Executive Officer
ENSERCH Corporation

William T. McCormick, Jr.
Chairman and Chief Executive Officer
CMS Energy Corporation

Thomas F. McLarty, III
Immediate Past Chairman of the Board and
Chief Executive Officer
Arkla, Inc.

Jerry R. McLeod
Executive Vice President
Pacific Gas and Electric Company

Jack W. McNutt
President and Chief Executive Officer
Murphy Oil Corporation

Frank A. McPherson
Chairman and Chief Executive Officer
Kerr-McGee Corporation

Cary M. Maguire
President
Maguire Oil Company

Frederick R. Mayer
President
Petroro Corporation

Judy Meidinger
Director
Koniag, Inc.

C. John Miller
Partner
Miller Energy Company

George P. Mitchell
Chairman of the Board, President
and Chief Executive Officer
Mitchell Energy and Development Corp.

James R. Moffett
Chairman of the Board and
Chief Executive Officer
Freeport-McMoRan Inc.

Donald I. Moritz
President and Chief Executive Officer
Equitable Resources, Inc.

William Moss
Chairman of the Board
William Moss Corporation

William D. Mounger
President
Delta Royalty Company, Inc.

John Thomas Munro
President
Munro Petroleum & Terminal Corporation

John J. Murphy
Chairman of the Board and
Chief Executive Officer
Dresser Industries, Inc.

Allen E. Murray
Chairman of the Board, President
and Chief Executive Officer
Mobil Corporation

Robert L. Nance
President
Nance Petroleum Corporation

Constantine S. Nicandros
President and Chief Executive Officer
Conoco Inc.

Raymond J. O'Connor
Commissioner
New York Public Service Commission

C. R. Palmer
Chairman of the Board, President
and Chief Executive Officer
Rowan Companies, Inc.

Robert L. Parker
Chairman of the Board and
Chief Executive Officer
Parker Drilling Company

James L. Pate
President and Chief Executive Officer
Pennzoil Company

T. Boone Pickens, Jr.
Chairman of the Board and
Chief Executive Officer
MESA, Inc.

L. Frank Pitts
Owner
Pitts Energy Group

Chesley R. Pruet
President
Pruet Drilling Company

Lawrence G. Rawl
Chairman of the Board and
Chief Executive Officer
Exxon Corporation

Robert G. Reed III
Chairman of the Board, President and Chief Executive Officer
Pacific Resources, Inc.

Frank H. Richardson
President and Chief Executive Officer
Shell Oil Company

Corbin J. Robertson, Jr.
President
Quintana Minerals Corporation

Henry A. Rosenberg, Jr.
Chairman of the Board and Chief Executive Officer
Crown Central Petroleum Corporation

Carole Keeton Rylander
President
Rylander Consulting Group

G. Henry M. Schuler
Director
Energy Program
Center for Strategic and International Studies

C. J. Silas
Chairman of the Board and Chief Executive Officer
Phillips Petroleum Company

Donald M. Simmons
President
Simmons Royalty Company

Donald C. Slawson
Chairman of the Board and President
Slawson Companies

Weldon H. Smith
Chairman of the Board
Big 6 Drilling Company

William T. Smith
Immediate Past Chairman
Wolverine Exploration Company

Arlo G. Sorensen
President
M. H. Whittier Corporation

Richard J. Stegemeier
Chairman of the Board and Chief Executive Officer
Unocal Corporation

H. Leighton Steward
Chairman, President and Chief Executive Officer
The Louisiana Land and Exploration Company

Ross O. Swimmer
Of Counsel
Hall, Estill, Hardwick, Gable, Golden & Nelson, P.C.

Patrick F. Taylor
Chairman and Chief Executive Officer
Taylor Energy Company

Robert C. Thomas
Chairman and Chief Executive Officer
Tenneco Gas Company

Eugene A. Tracy
Immediate Past Chairman of the Executive Committee
Peoples Energy Corporation

H. A. True, Jr.
Partner
True Oil Company

Chester R. Upham, Jr.
Managing Co-Owner
Upham Oil & Gas Company

Edward O. Vetter
President
Edward O. Vetter & Associates, Inc.

L. O. Ward
Owner-President
Ward Petroleum Corporation

Joseph H. Williams
Chairman of the Board and Chief Executive Officer
The Williams Companies, Inc.

Larry E. Williams
President and Chief Executive Officer
National Cooperative Refinery Association

Irene S. Wischer
President and Chief Executive Officer
Panhandle Producing Company

William A. Wise
President and Chief Executive Officer
El Paso Natural Gas Company

Dalton J. Woods
President
Dalwood Corporation

James D. Woods
Chairman of the Board, President
and Chief Executive Officer
Baker Hughes Incorporated

O. S. Wyatt, Jr.
Chairman of the Board
The Coastal Corporation

John A. Yates
President
Yates Petroleum Corporation

Daniel H. Yergin
President
Cambridge Energy Research Associates

Henry Zarrow
President
Sooner Pipe & Supply Corporation

NATIONAL PETROLEUM COUNCIL

COMMITTEE ON NATURAL GAS

CHAIRMAN

Frank H. Richardson
President and
Chief Executive Officer
Shell Oil Company

GOVERNMENT COCHAIRMAN

James G. Randolph
Assistant Secretary
Fossil Energy
U.S. Department of Energy

VICE CHAIRMAN, TRANSMISSION

Kenneth L. Lay
Chairman and
Chief Executive Officer
Enron Corp.

VICE CHAIRMAN, DISTRIBUTION

Eugene A. Tracy
Immediate Past Chairman of the
Executive Committee
Peoples Energy Corporation

EX OFFICIO

Ray L. Hunt
Chairman
National Petroleum Council
c/o Hunt Oil Company

EX OFFICIO

Kenneth T. Derr
Vice Chairman
National Petroleum Council
c/o Chevron Corporation

SECRETARY

Marshall W. Nichols
Executive Director
National Petroleum Council

* * *

D. Euan Baird
Chairman, President and
Chief Executive Officer
Schlumberger Limited

Bruce Calder
President
Bruce Calder, Inc.

Scott L. Campbell
Partner
Washington Policy and Analysis

R. D. Cash
Chairman, President and
Chief Executive Officer
Questar Corporation

Collis P. Chandler, Jr.
President
Chandler & Associates, Inc.

John H. Croom
Chairman, President and
Chief Executive Officer
The Columbia Gas System, Inc.

Keys A. Curry, Jr.
Executive Vice President
Destec Energy, Inc.

John P. DesBarres
President and Chief Executive Officer
Transco Energy Company

Cortlandt S. Dietler
Chairman and Chief Executive Officer
Associated Natural Gas Corporation

Richard D. Farman
Chairman and Chief Executive Officer
Southern California Gas Company

NPC COMMITTEE ON NATURAL GAS

William L. Fisher
Director
Bureau of Economic Geology
University of Texas at Austin

Joe B. Foster
Chairman
Newfield Exploration Company

James W. Glanville*
General Partner
Lazard Freres & Co.

John J. Graham
President and Chief Executive Officer
Graham Resources Inc.

Fred R. Grote
Chairman of the Board and
Chief Executive Officer
DeGolyer and MacNaughton

Ron W. Haddock
President and Chief Executive Officer
FINA, Inc.

Robert P. Hauptfuhrer
Chairman and Chief Executive Officer
Oryx Energy Company

Donald J. Heim
Chairman and Chief Executive Officer
Washington Gas Light Company

Frank O. Heintz
Chairman
Maryland Public Service Commission

Dennis R. Hendrix
Chairman, President and
Chief Executive Officer
Panhandle Eastern Corporation

C. Paul Hilliard
President/Owner
Badger Oil Corporation

Joseph T. Hydok
Executive Vice President, Gas Operations
Consolidated Edison Company
of New York, Inc.

Ray R. Irani
Chairman, President and
Chief Executive Officer
Occidental Petroleum Corporation

Bernard J. Kennedy
Chairman, President and
Chief Executive Officer
National Fuel Gas Company

James W. Kinnear
President and Chief Executive Officer
Texaco Inc.

Ronald L. Kuehn, Jr.
Chairman, President and
Chief Executive Officer
Sonat Inc.

William T. McCormick, Jr.
Chairman and Chief Executive Officer
CMS Energy Corporation

Thomas F. McLarty, III
Immediate Past Chairman of the Board and
Chief Executive Officer
Arkla, Inc.

Jerry R. McLeod
Executive Vice President
Pacific Gas and Electric Company

C. John Miller
Partner
Miller Energy Company

George P. Mitchell
Chairman of the Board, President and
Chief Executive Officer
Mitchell Energy and Development Corp.

Donald I. Moritz
President and Chief Executive Officer
Equitable Resources, Inc.

Allen E. Murray
Chairman of the Board, President and
Chief Executive Officer
Mobil Corporation

* Deceased (September 16, 1992)

Constantine S. Nicandros
President and Chief Executive Officer
Conoco Inc.

Robert L. Parker
Chairman of the Board and
Chief Executive Officer
Parker Drilling Company

L. Frank Pitts
Owner
Pitts Energy Group

Lawrence G. Rawl
Chairman of the Board and
Chief Executive Officer
Exxon Corporation

C. J. Silas
Chairman of the Board and
Chief Executive Officer
Phillips Petroleum Company

Robert C. Thomas
Chairman and Chief Executive Officer
Tenneco Gas

L. O. Ward
Owner-President
Ward Petroleum Corporation

William A. Wise
President and Chief Executive Officer
El Paso Natural Gas Company

NATIONAL PETROLEUM COUNCIL

COORDINATING SUBCOMMITTEE
OF THE
NPC COMMITTEE ON NATURAL GAS

CHAIRMAN

Lawrence L. Smith
Vice President Production
Shell Oil Company

GOVERNMENT COCHAIRMAN

Donald A. Juckett
Director
Office of Geoscience Research
U.S. Department of Energy

ASSISTANT TO THE CHAIRMAN

Alan J. Vennix
Manager Technology
Shell Oil Company

SECRETARY

Marshall W. Nichols
Executive Director
National Petroleum Council

* * *

Ronald J. Burns
Chairman and Chief Executive Officer
Enron Gas Pipeline and Marketing Group

Scott L. Campbell
Partner
Washington Policy and Analysis

Collis P. Chandler, Jr.
President
Chandler & Associates, Inc.

Joe B. Foster
Chairman
Newfield Exploration Company

Ray E. Galvin
President
Chevron U.S.A. Production Company

James W. Glanville*
General Partner
Lazaed Freres & Co.

Frank O. Heintz
Chairman
Maryland Public Service Commission

Frederick E. John
Senior Vice President
Southern California Gas Company

James R. Lee
Executive Vice President
Columbia Gas Distribution Companies

Michael G. Morris
Executive Vice President and
Chief Operating Officer
Consumers Power Company

Walter S. Piontek
Vice President, North American
Producing Operations
Mobil Oil Corporation

Oliver G. Richard III
Chairman and Chief Executive Officer
New Jersey Resources Corporation

William W. Slaughter
General Manager
Strategic Planning and Development
Texas Eastern Transmission Corporation

William A. Smith
Chairman and President
Southern Natural Gas Company

---

* Deceased (September 16, 1992)

NATIONAL PETROLEUM COUNCIL

TRANSMISSION AND STORAGE TASK GROUP
OF THE
NPC COMMITTEE ON NATURAL GAS

CHAIRMAN

William A. Smith
Chairman and President
Southern Natural Gas Company

GOVERNMENT COCHAIRMAN

Kevin P. Madden
Director
Office of Pipeline and Producer Regulations
Federal Energy Regulatory Commission

ASSISTANT TO THE CHAIRMAN

Steven C. Voorhees
Senior Vice President
Sonat Energy Services

SECRETARY

Benjamin A. Oliver, Jr.
Committee Coordinator
National Petroleum Council

* * *

Carl J. Croskey
Vice President
Facility Planning
ANR Pipeline Company

Cortlandt S. Dietler
Chairman and Chief Executive Officer
Associated Natural Gas Corporation

James M. Fay
Manager
Utility Systems and Residential/Commercial
Technology Analysis
Gas Research Institute

Roland V. Harris
Director, Gas Marketing
Oryx Energy Company

Joan E. Heinkel
Branch Chief
Reserves and Natural Gas Division
Data Analysis and Forecasting Branch
Energy Information Administration
U.S. Department of Energy

Richard H. Hilt
Manager, Strategic Planning
Electric Power Research Institute

Theodore L. Kinne
Vice President
Safety, Environment and Operations
Interstate Natural Gas Association of America

Lad P. Lorenz
Manager, Supply Operations
Southern California Gas Company

Brian E. O'Neill
President
Williams Natural Gas Company

James S. Prentice
Senior Vice President
Group Technical Services
Enron Gas Pipeline Group

Robert O. Reid
Vice President
Planning and Evaluation
Colorado Interstate Gas Company

Randall G. Schorre
Vice President, Engineering
Tenneco Gas

TRANSMISSION AND STORAGE TASK GROUP

William W. Slaughter
General Manager
Strategic Planning and Development
Texas Eastern Transmission Corporation

Dan J. Warden
Manager, Transmission & Exchange
Amoco Production Company

Jagjit Yadav
President
Sabine Pipe Line Company

Mendal L. Yoho
Senior Vice President
Marketing, Supply & Rates
CNG Transmission Corporation

SPECIAL ASSISTANTS

Ruth A. Concannon
Senior Coordinator
Gas Supply and Transportation
The Citrus Marketing Companies

Annette Del Barrio
Strategic Planning Analyst
Texas Eastern Transmission Corporation

Daniel P. Fowler
Manager, Competitive Analysis
Customer Services
CNG Transmission Corporation

Peter S. Gambel
Senior Business Development Analyst
Sonat Marketing Company

Scott J. Garner
Senior Planning Analyst
Planning and Evaluation
Colorado Interstate Gas Company

Don J. Humphries
Transportation & Exchange
Amoco Production Company

J. Richard Jones
Staff Vice President
Policy Analysis
Williams Natural Gas Company

Stephen T. Long
Competitive Analysis
Strategic Planning
Enron Corp.

Barbara Mariner-Volpe
Supervisor
Operation Research Analyst
Reserves and Natural Gas Division
Data Analysis and Forecasting Branch
Energy Information Administration
U.S. Department of Energy

W. Norris McKenzie
Project Manager
Sonat Energy Services.

William E. Murrell
Special Assistant to the Director
Office of Pipeline and Producer Regulation
Federal Energy Regulatory Commission

Edmund P. Perry
Corporate Counsel
Sonat Services Inc.

William E. Wickman
Senior Design Engineer
Tenneco Gas

Joseph L. Yestrepsky
Project Manager
Facility Planning
ANR Pipeline Company

Appendix C
Existing System Study

Table of Contents

SUMMARY

This appendix contains information on the existing and planned region-to-region capacity of 38 U.S. (and one Canadian) interstate pipeline companies. Also included are tables showing the capacity of storage fields in the United States. The pipeline data was initially compiled from Federal Energy Regulatory Commission (FERC) records.[1] Copies of the draft data were then circulated among members of the Transmission and Storage Task Group for comment. The storage data was compiled from FERC records and from the American Gas Association (AGA) storage database. In addition, Interstate Natural Gas Association of America (INGAA) sent a survey of the draft data to member pipelines for review and confirmation.[2] Responses to this inquiry were incorporated into the attached tables.

The Transmission and Storage Task Group would like to thank all of the individuals who helped compile and verify this information, and INGAA for their help in verifying the capacity data.

METHODOLOGY

Pipeline capacity was measured at the boundary of ten regions. A map showing the regions is contained in this appendix (page C-4).

The use of 1989 as a base year was required so the results of this study could be integrated with the other modeling efforts used to examine demand and supply. While data were not gathered for 1990, the capacity added to the interstate pipelines during that year are contained in the 1991 figures. No attempt was made here to quantify the capacity additions which may be planned, or required, in future years examined in the study. However, estimates of potential future capacity needs are contained in other portions of this report.

An important point of methodology is the basis used to derive the pipeline capacity figures. The capacity measured is based on engineering calculations of each of the individual pipeline companies. Many assumptions go into each of these calculations. These assumptions may vary significantly from company to company. There was no way, in this study, to normalize these assumptions to a common basis. However, we believe that these figures present a reasonable baseline from which to evaluate capacity.

Second, these figures represent forward haul capacity. Significant additional gas flows may be possible through the use of contractual devices such as back hauls and exchanges.[3] To some extent, some of the capacity figures already represent, implicitly, the effects of such arrangements.

Third, the capacity figures presented here are based on facilities in place today and projects which have already received regulatory approval. New projects may have been conceived, or proposed before regulatory bodies, which are not reflected here.

A BRIEF DESCRIPTION OF THE DATA TABLES

Table 1: Net Interstate Pipeline Capacity by Study Region (1989 and 1991–1994)

This table summarizes the net capacity into each region for the years 1989, and 1991 through 1994. The "Net" line only accounts for gas that may be transported into or out of a region on a peak day, but does not include gas that was produced and consumed within a region. However, this number does indicate which of the regions supply more than they consume (negative net) and which consume more than they supply (positive net).

It is interesting to note that the Mid-Atlantic region is projected to become a net exporter of gas. This is due to the large storage capacity in the region. This storage capacity is used to meet the peak day demands of the Mid-Atlantic, New York/New Jersey, New England, Midwest, and (by displacement) Southeast regions.

[1] These records included Exhibits G, G-I, and G-II from applications before the FERC, supplemental flow information filed in these applications, and Form 567 annual flow diagrams.

[2] A copy of the INGAA survey is attached to this appendix. See page C-43.

[3] These terms are defined in the glossary attached to this report (see Appendix F).

Tables 2–6: Summaries of Interstate Pipeline Regional Border Crossing Capacity (1989 and 1991–1994)

The Table 2 shows the 1989 border crossing capacity of the 38 major interstate pipelines which cross regional boundaries and TransCanada PipeLines Ltd.[4] Major LNG import terminals are also included in the table. The line "Summation of National Capacity" reflects the total inter-regional pipeline capacity in 1989.

Tables 3 through 6 provide the same information for the years 1991 through 1994.

Table 7: Total U.S. Storage by NPC Region

This table summarizes the capacity and deliverability of all storage fields within each of the study regions. In all, the capacities of 380 underground storage fields were examined. All volumes are stated in millions of cubic feet (MMCF).

Included in these tables is information on:

- "Certificated capacity" (the maximum volume of gas which may be stored in a given field, as set by regulatory authorities)
- "Maximum operating capacity" (the current maximum volume of gas which may be stored)[5]
- "Cushion gas volume" (the volume of gas which must remain in the reservoir at all times to maintain sufficient reservoir pressure and withdrawal rates)
- "Working gas volume" (the volume of gas which may be removed from storage during a normal withdrawal cycle—usually a winter season)
- "Peak day deliverability rate" (the volume of gas which may be withdrawn from storage on an expected peak day)
- "Design day deliverability rate" (the maximum volume of gas which may be withdrawn from storage, when the reservoir is full).

Table 8: Incremental Regional Border Crossing Capacity Increases Sorted by Region of Origin (1989 and 1991–1994)

This table shows a breakdown of the individual pipeline border crossing capacity sorted by the "region of origin." Included are the 1989 capacity and the incremental capacity approved by the relevant regulatory authority for the years 1991 through 1994.

Table 9: Incremental Regional Border Crossing Capacity Increases Sorted by Region of Destination (1989 and 1991–1994)

This table shows a breakdown of the individual pipeline border crossing capacity sorted by the "region of destination." Included are the 1989 capacity and the incremental capacity approved the relevant regulatory authority for the years 1991 through 1994.

Table 10: Alphabetical List of Interstate Pipeline Regional Border Crossing Capacity (1989 and 1991–1994)

This list of interstate pipelines shows the capacity of each pipeline at the regional border crossing points.

Table 11: Current Storage Capacity by Study Regions

This table lists the capacity and deliverability of individual storage fields. These storage facilities are sorted by region and state.

---

[4] The 38 pipelines chosen for the Existing System Study are those which have facilities crossing one or more of the ten regions used in the study. Other major pipelines were not included because they are wholly included within one of the study regions.

[5] The difference between "certificated capacity" and "maximum operating capacity" is due to: operating limitations discovered after certification; a storage field not yet developed to its certificated potential; and storage fields where installed surface facilities (wells, compressors, dehydrators, etc.) are insufficient to store and/or deliver the certificated capacity.

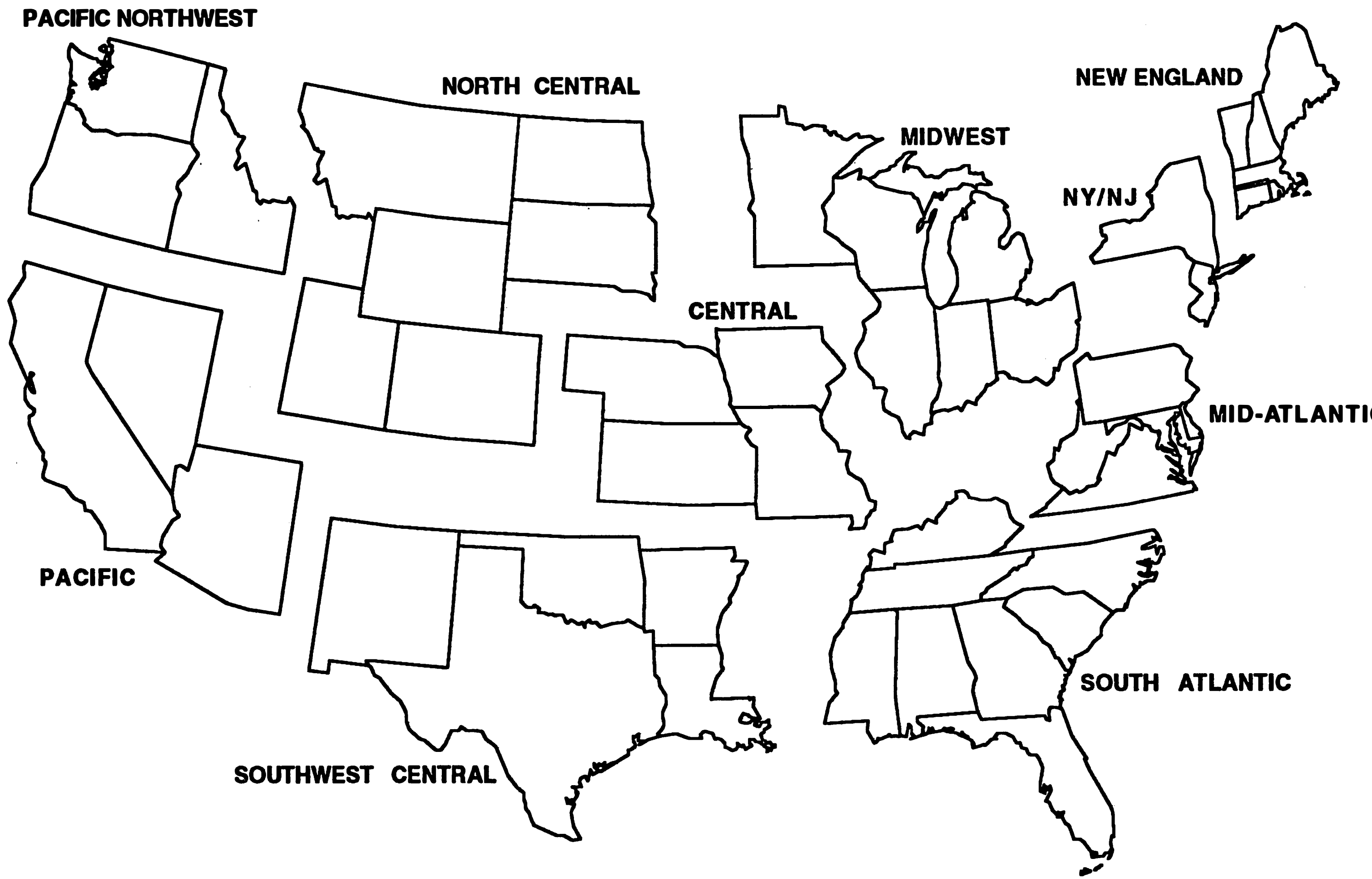


Figure C-1. NPC Capacity Study Regions.

TABLE 1

SUMMARY OF REGIONAL NET PIPELINE CAPACITY (1989 AND 1991-1994)

Region	**Capacity in MMCF/D**				
	1989	**1991**	**1992**	**1993**	**1994**
New England					
To	1,925	2,318	2,866	2,866	2,866
From	0	0	205	205	205
Net	**1,925**	**2,318**	**2,661**	**2,661**	**2,661**
NY/NJ					
To	7,601	8,891	10,087	10,405	10,405
From	1,666	2,059	2,732	2,752	2,752
Net	**5,935**	**6,832**	**7,355**	**7,653**	**7,653**
Mid-Atlantic					
To	8,985	9,160	9,445	9,625	9,625
From	8,328	9,167	9,560	9,878	9,878
Net	**657**	**(7)**	**(115)**	**(253)**	**(253)**
South Atlantic					
To	19,452	19,490	19,590	19,590	19,590
From	14,487	14,540	14,652	14,799	14,799
Net	**4,965**	**4,950**	**4,938**	**4,791**	**4,791**
Midwest					
To	21,167	21,600	22,464	22,611	22,611
From	6,704	7,077	8,032	8,257	8,257
Net	**14,463**	**14,523**	**14,432**	**14,354**	**14,354**
Southwest Central					
To	2,197	2,348	2,348	2,382	2,382
From	34,064	34,331	35,177	35,192	35,192
Net	**(31,867)**	**(31,983)**	**(32,829)**	**(32,810)**	**(32,810)**
Central					
To	11,530	11,760	12,073	12,073	12,073
From	7,690	7,772	7,793	7,793	7,793
Net	**3,840**	**3,988**	**4,280**	**4,280**	**4,280**
North Central					
To	2,507	2,828	3,083	3,149	3,885
From	3,510	3,811	4,824	4,964	4,964
Net	**(1,003)**	**(983)**	**(1,741)**	**(1,815)**	**(1,079)**

TABLE 1 (Continued)

Region	Capacity in MMCF/D 1989	1991	1992	1993	1994
Pacific					
To	5,577	5,577	7,023	7,821	7,821
From	0	0	0	0	0
Net	**5,577**	**5,577**	**7,023**	**7,821**	**7,821**
Pacific Northwest					
To	2,696	2,696	2,696	3,911	3,911
From	1,517	1,517	1,517	2,366	2,366
Net	**1,179**	**1,179**	**1,179**	**1,545**	**1,545**
Canada					
To	985	1,048	1,530	1,575	1,575
From	5,671	6,457	7,728	8,837	9,573
Net	**(4,686)**	**(5,409)**	**(6,198)**	**(7,262)**	**(7,998)**
Mexico					
To	370	370	370	370	370
From	370	370	370	370	370
Net	**0**	**0**	**0**	**0**	**0**

TABLE 2

1989 DESIGN PEAK DAY PIPELINE CAPACITY
(All Volumes in MMCF/D)

From Region	To Region					
	New Eng	NY/NJ	Mid-Atl	S. Atl	Midwest	SW Cen
NEW ENG	0	0	0	0	0	0
NY/NJ	1,608	0	58	0	0	0
MID-ATL	0	7,333	0	0	995	0
S ATL	0	0	4,588	0	9,865	34
MIDWEST	0	0	4,339	0	0	0
SW CEN	0	0	0	19,452	0	0
CENTRAL	0	0	0	0	7,170	160
N CEN	0	0	0	0	1,213	933
PAC	0	0	0	0	0	0
PAC NW	0	0	0	0	0	0
CANADA	32	268	0	0	1,924	0
MEXICO	0	0	0	0	0	370
LNG (A)*	285	0	0	0	0	700
TOTAL	**1,925**	**7,601**	**8,985**	**19,452**	**21,167**	**2,197**
LNG (IN)	0	0	1,000	500	0	0

From Region	To Region						
	Central	N Cen	Pac	Pac NW	Canada	Mexico	Total
NEW ENG	0	0	0	0	0	0	0
NY/NJ	0	0	0	0	0	0	1,666
MID-ATL	0	0	0	0	0	0	8,328
S ATL	0	0	0	0	0	0	14,487
MIDWEST	1,380	0	0	0	985	0	6,704
SW CEN	9,110	813	4,319	0	0	370	34,064
CENTRAL	0	360	0	0	0	0	7,690
N CEN	1,040	0	0	324	0	0	3,510
PAC	0	0	0	0	0	0	0
PAC NW	0	259	1,258	0	0	0	1,517
CANADA	0	1,075	0	2,372	0	0	5,671
MEXICO	0	0	0	0	0	0	370
LNG (A)	0	0	0	0	0	0	985
TOTAL	**11,530**	**2,507**	**5,577**	**2,696**	**985**	**370**	**84,992**
LNG (IN)	0	0	0	0	0	0	1,500

Summation of National Capacity = 83,637 MMCF/D†

* LNG capacity is either active ("A") or inactive ("IN").

† Net of exports to Mexico and Canada, and exclusive of inactive LNG plant volumes.

TABLE 3

1991 DESIGN PEAK DAY PIPELINE CAPACITY
(All Volumes in MMCF/D)

From Region	To Region					
	New Eng	NY/NJ	Mid-Atl	S. Atl	Midwest	SW Cen
NEW ENG	0	0	0	0	0	0
NY/NJ	2,001	0	58	0	0	0
MID-ATL	0	8,148	0	24	995	0
S ATL	0	0	4,601	0	9,905	34
MIDWEST	0	0	4,501	0	0	0
SW CEN	0	0	0	19,466	0	0
CENTRAL	0	0	0	0	7,252	160
N CEN	0	0	0	0	1,363	1,084
PAC	0	0	0	0	0	0
PAC NW	0	0	0	0	0	0
CANADA	32	743	0	0	2,085	0
MEXICO	0	0	0	0	0	370
LNG (A)*	285	0	0	0	0	700
TOTAL	**2,318**	**8,891**	**9,160**	**19,490**	**21,600**	**2,348**
LNG (IN)	0	0	1,000	500	0	0

From Region	To Region						
	Central	N Cen	Pac	Pac NW	Canada	Mexico	Total
NEW ENG	0	0	0	0	0	0	0
NY/NJ	0	0	0	0	0	0	2,059
MID-ATL	0	0	0	0	0	0	9,167
S ATL	0	0	0	0	0	0	14,540
MIDWEST	1,528	0	0	0	1,048	0	7,077
SW CEN	9,192	984	4,319	0	0	370	34,331
CENTRAL	0	360	0	0	0	0	7,772
N CEN	1,040	0	0	324	0	0	3,811
PAC	0	0	0	0	0	0	0
PAC NW	0	259	1,258	0	0	0	1,517
CANADA	0	1,225	0	2,372	0	0	6,457
MEXICO	0	0	0	0	0	0	370
LNG (A)	0	0	0	0	0	0	985
TOTAL	**11,760**	**2,828**	**5,577**	**2,696**	**1,048**	**370**	**88,086**
LNG (IN)	0	0	0	0	0	0	1,500

Summation of National Capacity = 86,668 MMCF/D†

* LNG capacity is either active ("A") or inactive ("IN").

† Net of exports to Mexico and Canada, and exclusive of inactive LNG plant volumes.

TABLE 4

1992 DESIGN PEAK DAY PIPELINE CAPACITY
(All Volumes in MMCF/D)

From Region	To Region					
	New Eng	NY/NJ	Mid-Atl	S. Atl	Midwest	SW Cen
NEW ENG	0	205	0	0	0	0
NY/NJ	2,549	0	183	0	0	0
MID-ATL	0	8,541	0	24	995	0
S ATL	0	0	4,601	0	10,017	34
MIDWEST	0	0	4,661	0	0	0
SW CEN	0	0	0	19,566	0	0
CENTRAL	0	0	0	0	7,273	160
N CEN	0	0	0	0	1,676	1,084
PAC	0	0	0	0	0	0
PAC NW	0	0	0	0	0	0
CANADA	32	1,341	0	0	2,503	0
MEXICO	0	0	0	0	0	370
LNG (A)*	285	0	0	0	0	700
TOTAL	**2,866**	**10,087**	**9,445**	**19,590**	**22,464**	**2,348**
LNG (IN)	0	0	1,000	500	0	0

From Region	To Region						
	Central	N Cen	Pac	Pac NW	Canada	Mexico	Total
NEW ENG	0	0	0	0	0	0	205
NY/NJ	0	0	0	0	0	0	2,732
MID-ATL	0	0	0	0	0	0	9,560
S ATL	0	0	0	0	0	0	14,652
MIDWEST	1,841	0	0	0	1,530	0	8,032
SW CEN	9,192	984	5,065	0	0	370	35,177
CENTRAL	0	360	0	0	0	0	7,793
N CEN	1,040	0	700	324	0	0	4,824
PAC	0	0	0	0	0	0	0
PAC NW	0	259	1,258	0	0	0	1,517
CANADA	0	1,480	0	2,372	0	0	7,728
MEXICO	0	0	0	0	0	0	370
LNG (A)	0	0	0	0	0	0	985
TOTAL	**12,073**	**3,083**	**7,023**	**2,696**	**1,530**	**370**	**93,575**
LNG (IN)	0	0	0	0	0	0	1,500

Summation of National Capacity = 91,675 MMCF/D†

* LNG capacity is either active ("A") or inactive ("IN").

† Net of exports to Mexico and Canada, and exclusive of inactive LNG plant volumes.

TABLE 5

1993 DESIGN PEAK DAY PIPELINE CAPACITY
(All Volumes in MMCF/D)

From Region	To Region: New Eng	NY/NJ	Mid-Atl	S. Atl	Midwest	SW Cen
NEW ENG	0	205	0	0	0	0
NY/NJ	2,569	0	183	0	0	0
MID-ATL	0	8,859	0	24	995	0
S ATL	0	0	4,601	0	10,164	34
MIDWEST	0	0	4,841	0	0	0
SW CEN	0	0	0	19,566	0	0
CENTRAL	0	0	0	0	7,273	160
N CEN	0	0	0	0	1,676	1,118
PAC	0	0	0	0	0	0
PAC NW	0	0	0	0	0	0
CANADA	32	1,341	0	0	2,503	0
MEXICO	0	0	0	0	0	370
LNG (A)*	285	0	0	0	0	700
TOTAL	**2,886**	**10,405**	**9,625**	**19,590**	**22,611**	**2,382**
LNG (IN)	0	0	1,000	500	0	0

From Region	To Region: Central	N Cen	Pac	Pac NW	Canada	Mexico	Total
NEW ENG	0	0	0	0	0	0	205
NY/NJ	0	0	0	0	0	0	2,752
MID-ATL	0	0	0	0	0	0	9,878
S ATL	0	0	0	0	0	0	14,799
MIDWEST	1,841	0	0	0	1,575	0	8,257
SW CEN	9,192	999	5,065	0	0	370	35,192
CENTRAL	0	360	0	0	0	0	7,793
N CEN	1,040	0	700	430	0	0	4,964
PAC	0	0	0	0	0	0	0
PAC NW	0	310	2,056	0	0	0	2,366
CANADA	0	1,480	0	3,481	0	0	8,837
MEXICO	0	0	0	0	0	0	370
LNG (A)	0	0	0	0	0	0	985
TOTAL	**12,073**	**3,149**	**7,821**	**3,911**	**1,575**	**370**	**96,398**
LNG (IN)	0	0	0	0	0	0	1,500

Summation of National Capacity = 94,453 MMCF/D†

* LNG capacity is either active ("A") or inactive ("IN").

† Net of exports to Mexico and Canada, and exclusive of inactive LNG plant volumes.

TABLE 6

1994 DESIGN PEAK DAY PIPELINE CAPACITY
(All Volumes in MMCF/D)

From Region	To Region					
	New Eng	NY/NJ	Mid-Atl	S. Atl	Midwest	SW Cen
NEW ENG	0	205	0	0	0	0
NY/NJ	2,569	0	183	0	0	0
MID-ATL	0	8,859	0	24	995	0
S ATL	0	0	4,601	0	10,164	34
MIDWEST	0	0	4,841	0	0	0
SW CEN	0	0	0	19,566	0	0
CENTRAL	0	0	0	0	7,273	160
N CEN	0	0	0	0	1,676	1,118
PAC	0	0	0	0	0	0
PAC NW	0	0	0	0	0	0
CANADA	32	1,341	0	0	2,503	0
MEXICO	0	0	0	0	0	370
LNG (A)*	285	0	0	0	0	700
TOTAL	**2,886**	**10,405**	**9,625**	**19,590**	**22,611**	**2,382**
LNG (IN)	0	0	1,000	500	0	0

From Region	To Region						
	Central	N Cen	Pac	Pac NW	Canada	Mexico	Total
NEW ENG	0	0	0	0	0	0	205
NY/NJ	0	0	0	0	0	0	2,752
MID-ATL	0	0	0	0	0	0	9,878
S ATL	0	0	0	0	0	0	14,799
MIDWEST	1,841	0	0	0	1,575	0	8,257
SW CEN	9,192	999	5,065	0	0	370	35,192
CENTRAL	0	360	0	0	0	0	7,793
N CEN	1,040	0	700	430	0	0	4,964
PAC	0	0	0	0	0	0	0
PAC NW	0	310	2,056	0	0	0	2,366
CANADA	0	2,216	0	3,481	0	0	9,573
MEXICO	0	0	0	0	0	0	370
LNG (A)	0	0	0	0	0	0	985
TOTAL	**12,073**	**3,885**	**7,821**	**3,911**	**1,575**	**370**	**97,134**
LNG (IN)	0	0	0	0	0	0	1,500

Summation of National Capacity = 95,189 MMCF/D†

* LNG capacity is either active ("A") or inactive ("IN").

† Net of exports to Mexico and Canada, and exclusive of inactive LNG plant volumes.

TABLE 7

TOTAL U.S. STORAGE CAPACITY BY NPC REGION

Region	Certificated Capacity (MMCF)	Maximum Operating Capacity (MMCF)	Cushion Gas Volume (MMCF)	Working Gas Volume (MMCF)	Peak Day Del. Rate (MMCF/D)	Design Day Del. Rate (MMCF/D)
New England	0	0	0	0	0	0
NY/NJ	173,680	173,680	91,957	81,723	1,008	1,243
Mid-Atlantic	1,321,288	1,309,446	749,060	554,922	11,269	11,737
South Atlantic	327,106	325,836	153,434	176,519	3,395	4,616
Midwest	2,803,649	2,653,700	1,581,539	1,075,541	17,792	20,493
Central	727,730	689,434	377,284	312,150	2,713	3,587
Southwest Central	1,747,076	1,591,159	776,703	815,406	10,058	11,765
North Central	686,879	650,478	342,807	307,699	1,870	1,970
Pacific Northwest	33,900	33,900	18,800	15,100	450	522
Pacific	463,167	460,561	246,161	214,400	5,100	5,990
Total U.S.	**8,284,475**	**7,888,194**	**4,337,745**	**3,553,460**	**53,655**	**61,923**

TABLE 8

DESIGN DAY PIPELINE CAPACITY BY REGION OF ORIGIN

Company	Capacity 1989	Incremental Capacity in MMCF/D 1991	1992	1993	1994
Alberta To North Central					
Altamont	0	0	0	0	736
Brit. Colum. To Pacific Northwest					
Northwest	790	0	0	256	0
Pacific Gas	1,582	0	0	853	0
Total British Columbia	**2,372**	**0**	**0**	**1,109**	**0**
Central To Midwest					
ANR	513	82	0	0	0
Mississippi River	477	0	0	0	0
Natural	3,280	0	0	0	0
Northern Natural	247	0	21	0	0
Northern Natural	1,050	0	0	0	0
Panhandle	1,361	0	0	0	0
Texas Eastern	242	0	0	0	0
Subtotal	**7,170**	**82**	**21**	**0**	**0**
Central To North Central					
CIG	360	0	0	0	0
Central To Southwest Central					
CIG	160	0	0	0	0
Total Central	**7,690**	**82**	**21**	**0**	**0**
Manitoba To Midwest					
Great Lakes	1,518	149	418	0	0
Viking	406	12	0	0	0
Total Manitoba	**1,924**	**161**	**418**	**0**	**0**
Mexico To Southwest Central					
Texas Eastern	370	0	0	0	0
Mid-Atlantic To Midwest					
CNG	995	0	0	0	0

TABLE 8 (Continued)

Company	Capacity 1989	Incremental Capacity in MMCF/D 1991	1992	1993	1994
Mid-Atlantic To NY/NJ					
CNG	1,370	90	25	65	0
Columbia	205	126	42	0	0
National Fuel	205	0	0	0	0
Tennessee	858	0	40	20	0
Texas Eastern	2,307	287	37	60	0
Transcontinental	2,388	312	249	173	0
Subtotal	**7,333**	**815**	**393**	**318**	**0**
Mid-Atlantic To South Atlantic					
Columbia	0	24	0	0	0
Total Mid-Atlantic	**8,328**	**839**	**393**	**318**	**0**
Midwest To Central					
Mississippi River	275	0	0	0	0
Northern Border	1,105	148	313	0	0
Subtotal	**1,380**	**148**	**313**	**0**	**0**
Midwest To Mid-Atlantic					
CNG	320	0	160	180	0
Tennessee	1,637	0	0	0	0
Texas Eastern	2,382	162	0	0	0
Subtotal	**4,339**	**162**	**160**	**180**	**0**
Midwest To Ontario					
Great Lakes	935	63	418	0	0
Panhandle	50	0	64	45	0
Subtotal	**985**	**63**	**482**	**45**	**0**
Total Midwest	**6,704**	**373**	**955**	**225**	**0**
New England To NY/NJ					
Iroquois	0	0	205	0	0
North Central To Central					
CIG	360	0	0	0	0
KN Energy	137	0	0	0	0
Trailblazer	387	0	0	0	0
Williams	156	0	0	0	0
Subtotal	**1,040**	**0**	**0**	**0**	**0**
North Central To Midwest					
Northern Border	1,213	150	313	0	0

TABLE 8 (Continued)

Company	Capacity 1989	Incremental Capacity in MMCF/D 1991	1992	1993	1994
North Central To Pacific Northwest					
Northwest	324	0	0	106	0
North Central To Pacific					
Kern River	0	0	700	0	0
North Central To Southwest Central					
CIG	200	0	0	0	0
El Paso	433	151	0	0	0
Northwest	300	0	0	34	0
Subtotal	**933**	**151**	**0**	**34**	**0**
Total North Central	**3,510**	**301**	**1,013**	**140**	**0**
NY/NJ To Mid-Atlantic					
National Fuel	0	0	125	0	0
Penn-York	58	0	0	0	0
Subtotal	**58**	**0**	**125**	**0**	**0**
NY/NJ To New England					
Algonquin	890	128	25	0	0
Iroquois	0	0	332	0	0
Tennessee	718	265	191	20	0
Subtotal	**1,608**	**393**	**548**	**20**	**0**
Total NY/NJ	**1,666**	**393**	**673**	**20**	**0**
Ontario To NY/NJ					
Iroquois	0	0	576	0	0
Tennessee	268	475	22	0	0
Total Ontario	**268**	**475**	**598**	**0**	**0**
Pacific Northwest To North Central					
Northwest	259	0	0	51	0
Pacific Northwest To Pacific					
Northwest	128	0	0	32	0
Pacific Gas	1,130	0	0	766	0
Subtotal	**1,258**	**0**	**0**	**798**	**0**
Total Pacific Northwest	**1,517**	**0**	**0**	**849**	**0**
Quebec To New England					
Vermont Gas	32	0	0	0	0

TABLE 8 (Continued)

Company	Capacity 1989	Incremental Capacity in MMCF/D 1991	1992	1993	1994
Saskatchewan To North Central					
Northern Border	1,075	150	255	0	0
South Atlantic To Mid-Atlantic					
Columbia	1,420	13	0	0	0
East Tennessee	10	0	0	0	0
Tennessee	796	0	0	0	0
Transcontinental	2,362	0	0	0	0
Subtotal	**4,588**	**13**	**0**	**0**	**0**
South Atlantic To Midwest					
ANR	1,315	0	0	0	0
Columbia	839	0	0	0	0
Midwestern	663	0	0	0	0
Tennessee	1,678	0	0	0	0
Texas Eastern	2,066	0	0	0	0
Texas Gas	1,497	40	112	147	0
Trunkline	1,807	0	0	0	0
Subtotal	**9,865**	**40**	**112**	**147**	**0**
South Atlantic To Southwest Central					
Arkla	34	0	0	0	0
Total South Atlantic	**14,487**	**53**	**112**	**147**	**0**
Southwest Central To Central					
ANR	622	82	0	0	0
Arkla	200	0	0	0	0
CIG	160	0	0	0	0
Mississippi River	730	0	0	0	0
Natural	2,900	0	0	0	0
Northern Natural	2,050	0	0	0	0
Panhandle	1,475	0	0	0	0
Texas Eastern	300	0	0	0	0
Williams	673	0	0	0	0
Subtotal	**9,110**	**82**	**0**	**0**	**0**
Southwest Central To Mexico					
Texas Eastern	370	0	0	0	0
Southwest Central To North Central					
CIG	200	0	0	0	0
El Paso	313	171	0	0	0
Northwest	300	0	0	15	0
Subtotal	**813**	**171**	**0**	**15**	**0**

TABLE 8 (Continued)

Company	Capacity 1989	Incremental Capacity in MMCF/D 1991	1992	1993	1994
Southwest Central To South Atlantic					
ANR	1,350	0	0	0	0
Columbia Gulf	2,133	0	0	0	0
Florida Gas	825	0	100	0	0
Southern Natural	1,665	14	0	0	0
Tennessee	3,975	0	0	0	0
Texas Eastern	1,525	0	0	0	0
Texas Gas	2,120	0	0	0	0
Transcontinental	3,056	0	0	0	0
Trunkline	1,853	0	0	0	0
United	950	0	0	0	0
Subtotal	**19,452**	**14**	**100**	**0**	**0**
Southwest Central To Pacific					
El Paso	3,569	0	406	0	0
Transwestern	750	0	340	0	0
Subtotal	**4,319**	**0**	**746**	**0**	**0**
Total Southwest Central	**34,064**	**267**	**846**	**15**	**0**

Canadian Inter-Provincial Pipeline Capacity*

Company	Capacity 1989	1991	1992	1993	1994
Alberta To Saskatchewan					
TransCanada	N/A	4,640	394	177	87
Manitoba To Midwest					
TransCanada	N/A	2,412	30	0	1
Manitoba To Ontario					
TransCanada	N/A	2,345	364	282	80
Midwest To Ontario					
TransCanada	N/A	1,255	0	0	0
Ontario To NY/NJ					
TransCanada	N/A	1,097	359	380	55
Ontario To Quebec					
TransCanada	N/A	878	0	59	0
Quebec To New England					
TransCanada	N/A	63	0	0	0
Saskatchewan To Manitoba					
TransCanada	N/A	5,070	394	177	87

* TransCanada provided capacity information using 1991/92 as a base year, and incremental capacity additions for 1992/93, 1993/94 and 1994/95.

TABLE 9

DESIGN DAY PIPELINE CAPACITY BY REGION OF DESTINATION

Company	Capacity 1989	Incremental Capacity In MMCF/Day 1991	1992	1993	1994
Midwest To Central					
Mississippi River	275	0	0	0	0
Northern Border	1,105	148	313	0	0
Subtotal	**1,380**	**148**	**313**	**0**	**0**
North Central To Central					
CIG	360	0	0	0	0
KN Energy	137	0	0	0	0
Trailblazer	387	0	0	0	0
Williams	156	0	0	0	0
Subtotal	**1,040**	**0**	**0**	**0**	**0**
Southwest Central To Central					
ANR	622	82	0	0	0
Arkla	200	0	0	0	0
CIG	160	0	0	0	0
Mississippi River	730	0	0	0	0
Natural	2,900	0	0	0	0
Northern Natural	2,050	0	0	0	0
Panhandle	1,475	0	0	0	0
Texas Eastern	300	0	0	0	0
Williams	673	0	0	0	0
Subtotal	**9,110**	**82**	**0**	**0**	**0**
Total Central	**11,530**	**230**	**313**	**0**	**0**
Southwest Central To Mexico					
Texas Eastern	370	0	0	0	0
Midwest To Mid-Atlantic					
CNG	320	0	160	180	0
Tennessee	1,637	0	0	0	0
Texas Eastern	2,382	162	0	0	0
Subtotal	**4,339**	**162**	**160**	**180**	**0**
NY/NJ To Mid-Atlantic					
National Fuel	0	0	125	0	0
Penn-York	58	0	0	0	0
Subtotal	**58**	**0**	**125**	**0**	**0**

TABLE 9 (Continued)

Company	Capacity 1989	Incremental Capacity In MMCF/Day 1991	1992	1993	1994
South Atlantic To Mid-Atlantic					
Columbia	1,420	13	0	0	0
East Tennessee	10	0	0	0	0
Tennessee	796	0	0	0	0
Transcontinental	2,362	0	0	0	0
Subtotal	**4,588**	**13**	**0**	**0**	**0**
Total Mid-Atlantic	**8,985**	**175**	**285**	**180**	**0**
Central To Midwest					
ANR	513	82	0	0	0
Mississippi River	477	0	0	0	0
Natural	3,280	0	0	0	0
Northern Natural	1,050	0	0	0	0
Northern Natural	247	0	21	0	0
Panhandle	1,361	0	0	0	0
Texas Eastern	242	0	0	0	0
Subtotal	**7,170**	**82**	**21**	**0**	**0**
Manitoba To Midwest					
Great Lakes	1,518	149	418	0	0
Viking	406	12	0	0	0
Subtotal	**1,924**	**161**	**418**	**0**	**0**
Mid-Atlantic To Midwest					
CNG	995	0	0	0	0
North Central To Midwest					
Northern Border	1,213	150	313	0	0
South Atlantic To Midwest					
ANR	1,315	0	0	0	0
Columbia	839	0	0	0	0
Midwestern	663	0	0	0	0
Tennessee	1,678	0	0	0	0
Texas Eastern	2,066	0	0	0	0
Texas Gas	1,497	40	112	147	0
Trunkline	1,807	0	0	0	0
Subtotal	**9,865**	**40**	**112**	**147**	**0**
Total Midwest	**21,167**	**433**	**864**	**147**	**0**

TABLE 9 (Continued)

Company	Capacity 1989	Incremental Capacity In MMCF/Day 1991	1992	1993	1994
NY/NJ To New England					
Algonquin	890	128	25	0	0
Iroquois	0	0	332	0	0
Tennessee	718	265	191	20	0
Subtotal	**1,608**	**393**	**548**	**20**	**0**
Quebec To New England					
Vermont Gas	32	0	0	0	0
Total New England	**1,640**	**393**	**548**	**20**	**0**
Alberta To North Central					
Altamont	0	0	0	0	736
Central To North Central					
CIG	360	0	0	0	0
Pacific Northwest To North Central					
Northwest	259	0	0	51	0
Saskatchewan To North Central					
Northern Border	1,075	150	255	0	0
Southwest Central To North Central					
CIG	200	0	0	0	0
El Paso	313	171	0	0	0
Northwest	300	0	0	15	0
Subtotal	**813**	**171**	**0**	**15**	**0**
Total North Central	**2,507**	**321**	**255**	**66**	**736**
Mid-Atlantic To NY/NJ					
CNG	1,370	90	25	65	0
Columbia	205	126	42	0	0
National Fuel	205	0	0	0	0
Tennessee	858	0	40	20	0
Texas Eastern	2,307	287	37	60	0
Transcontinental	2,388	312	249	173	0
Subtotal	**7,333**	**815**	**393**	**318**	**0**
New England To NY/NJ					
Iroquois	0	0	205	0	0
Ontario To NY/NJ					
Iroquois	0	0	576	0	0
Tennessee	268	475	22	0	0
Subtotal	**268**	**475**	**598**	**0**	**0**
Total NY/NJ	**7,601**	**1,290**	**1,196**	**318**	**0**

TABLE 9 (Continued)

Company	Capacity 1989	Incremental Capacity In MMCF/Day 1991	1992	1993	1994
Midwest To Ontario					
Great Lakes	935	63	418	0	0
Panhandle	50	0	64	45	0
Total Ontario	**985**	**63**	**482**	**45**	**0**
Brit. Colum. To Pacific Northwest					
Northwest	790	0	0	256	0
Pacific Gas	1,582	0	0	853	0
Subtotal	**2,372**	**0**	**0**	**1,109**	**0**
North Central To Pacific Northwest					
Northwest	324	0	0	106	0
Total Pacific Northwest	**2,696**	**0**	**0**	**1,215**	**0**
Mid-Atlantic To South Atlantic					
Columbia	0	24	0	0	0
Southwest Central To South Atlantic					
ANR	1,350	0	0	0	0
Columbia Gulf	2,133	0	0	0	0
Florida Gas	825	0	100	0	0
Southern Natural	1,665	14	0	0	0
Tennessee	3,975	0	0	0	0
Texas Eastern	1,525	0	0	0	0
Texas Gas	2,120	0	0	0	0
Transcontinental	3,056	0	0	0	0
Trunkline	1,853	0	0	0	0
United	950	0	0	0	0
Subtotal	**19,452**	**14**	**100**	**0**	**0**
Total South Atlantic	**19,452**	**38**	**100**	**0**	**0**
North Central To Pacific					
Kern River	0	0	700	0	0
Pacific Northwest To Pacific					
Northwest	128	0	0	32	0
Pacific Gas	1,130	0	0	766	0
Subtotal	**1,258**	**0**	**0**	**798**	**0**

TABLE 9 (Continued)

Company	Capacity 1989	Incremental Capacity In MMCF/Day 1991	1992	1993	1994
Southwest Central To Pacific					
El Paso	3,569	0	406	0	0
Transwestern	750	0	340	0	0
Subtotal	**4,319**	**0**	**746**	**0**	**0**
Total Pacific	**5,577**	**0**	**1,446**	**798**	**0**
Central To Southwest Central					
CIG	160	0	0	0	0
Mexico To Southwest Central					
Texas Eastern	370	0	0	0	0
North Central To Southwest Central					
CIG	200	0	0	0	0
El Paso	433	151	0	0	0
Northwest	300	0	0	34	0
Subtotal	**933**	**151**	**0**	**34**	**0**
South Atlantic To Southwest Central					
Arkla	34	0	0	0	0
Total Southwest Central	**1,497**	**151**	**0**	**34**	**0**
Canadian Inter-Provincial Pipeline Capacity*					
Saskatchewan To Manitoba					
TransCanada	N/A	5,070	394	177	87
Mantoba To Midwest					
TransCanada	N/A	2,412	30	0	1
Quebec To New England					
TransCanada	N/A	63	0	0	0
Ontario To NY/NJ					
TransCanada	N/A	1,097	359	380	55
Manitoba To Ontario					
TransCanada	N/A	2,345	364	282	80
Midwest To Ontario					
TransCanada	N/A	1,255	0	0	0
Ontario To Quebec					
TransCanada	N/A	878	0	59	0
Alberta To Saskatchewan					
TransCanada	N/A	4,640	394	177	87

* TransCanada provided capacity information using 1991/92 as a base year, and incremental capacity additions for 1992/93, 1993/94 and 1994/95.

TABLE 10

DESIGN DAY CAPACITY BY COMPANY

Company		Capacity 1989	Incremental Capacity In MMCF/D 1991	1992	1993	1994
Algonquin						
NY/NJ	New England	890	128	25	0	0
Altamont						
Alberta	North Central	0	0	0	0	736
ANR						
Southwest Central	Central	622	82	0	0	0
Central	Midwest	513	82	0	0	0
Southwest Central	South Atlantic	1,350	0	0	0	0
South Atlantic	Midwest	1,315	0	0	0	0
Arkla						
Southwest Central	Central	200	0	0	0	0
South Atlantic	Southwest Central	34	0	0	0	0
Colorado Interstate						
North Central	Southwest Central	200	0	0	0	0
Central	Southwest Central	160	0	0	0	0
Southwest Central	North Central	200	0	0	0	0
Southwest Central	Central	160	0	0	0	0
North Central	Central	360	0	0	0	0
Central	North Central	360	0	0	0	0
Columbia						
South Atlantic	Midwest	839	0	0	0	0
South Atlantic	Mid-Atlantic	1,420	13	0	0	0
Mid-Atlantic	NY/NJ	205	126	42	0	0
Mid-Atlantic	South Atlantic	0	24	0	0	0
Columbia Gulf						
Southwest Central	South Atlantic	2,133	0	0	0	0
Consolidated Natural Gas						
Midwest	Mid-Atlantic	320	0	160	180	0
Mid-Atlantic	NY/NJ	1,370	90	25	65	0
Mid-Atlantic	Midwest	995	0	0	0	0
East Tennessee						
South Atlantic	Mid-Atlantic	10	0	0	0	0
El Paso						
North Central	Southwest Central	433	151	0	0	0
Southwest Central	Pacific	3,569	0	406	0	0
Southwest Central	North Central	313	171	0	0	0

TABLE 10 (Continued)

Company		Capacity 1989	Incremental Capacity In MMCF/D 1991	1992	1993	1994
Florida Gas						
Southwest Central	South Atlantic	825	0	100	0	0
Great Lakes						
Manitoba	Midwest	1,518	149	418	0	0
Midwest	Ontario	935	63	418	0	0
Iroquois						
Ontario	NY/NJ	0	0	576	0	0
NY/NJ	New England	0	0	332	0	0
New England	NY/NJ	0	0	205	0	0
Kern River						
North Central	Pacific	0	0	700	0	0
KN Energy						
North Central	Central	137	0	0	0	0
Midwestern						
South Atlantic	Midwest	663	0	0	0	0
Mississippi River						
Southwest Central	Central	730	0	0	0	0
Midwest	Central	275	0	0	0	0
Central	Midwest	477	0	0	0	0
National Fuel						
Mid-Atlantic	NY/NJ	205	0	0	0	0
NY/NJ	Mid-Atlantic	0	0	125	0	0
Natural						
Southwest Central	Central	2,900	0	0	0	0
Central	Midwest	3,280	0	0	0	0
Northern Border						
Sask	North Central	1,075	150	255	0	0
North Central	Midwest	1,213	150	313	0	0
Midwest	Central	1,105	148	313	0	0
Northern Natural						
Southwest Central	Central	2,050	0	0	0	0
Central	Midwest	247	0	21	0	0
Central	Midwest	1,050	0	0	0	0
Northwest						
North Central	Pacific Northwest	324	0	0	106	0
Br Col	Pacific Northwest	790	0	0	256	0
North Central	Southwest Central	300	0	0	34	0
Pacific Northwest	Pacific	128	0	0	32	0
Southwest Central	North Central	300	0	0	15	0
Pacific Northwest	North Central	259	0	0	51	0

TABLE 10 (Continued)

Company		Capacity 1989	Incremental Capacity In MMCF/D 1991	1992	1993	1994
Pacific Gas						
Pacific Northwest	Pacific	1,130	0	0	766	0
Br Col	Pacific Northwest	1,582	0	0	853	0
Panhandle						
Central	Midwest	1,361	0	0	0	0
Midwest	Ontario	50	0	64	45	0
Southwest Central	Central	1,475	0	0	0	0
Penn-York						
NY/NJ	Mid-Atlantic	58	0	0	0	0
Southern Natural						
Southwest Central	South Atlantic	1,665	14	0	0	0
Tennessee						
South Atlantic	Mid-Atlantic	796	0	0	0	0
Mid-Atlantic	NY/NJ	858	0	40	20	0
Midwest	Mid-Atlantic	1,637	0	0	0	0
South Atlantic	Midwest	1,678	0	0	0	0
NY/NJ	New England	718	265	191	20	0
Ontario	NY/NJ	268	475	22	0	0
Southwest Central	South Atlantic	3,975	0	0	0	0
Texas Eastern						
South Atlantic	Midwest	2,066	0	0	0	0
Midwest	Mid-Atlantic	2,382	162	0	0	0
Mexico	Southwest Central	370	0	0	0	0
Central	Midwest	242	0	0	0	0
Southwest Central	Central	300	0	0	0	0
Mid-Atlantic	NY/NJ	2,307	287	37	60	0
Southwest Central	South Atlantic	1,525	0	0	0	0
Southwest Central	Mexico	370	0	0	0	0
Texas Gas						
South Atlantic	Midwest	1,497	40	112	147	0
Southwest Central	South Atlantic	2,120	0	0	0	0
Trailblazer						
North Central	Central	387	0	0	0	0

TABLE 10 (Continued)

Company		Capacity 1989	Incremental Capacity In MMCF/D 1991	1992	1993	1994
TransCanada						
Alberta	Sask	N/A	4,640	394	177	87
Sask	Manitoba	N/A	5,070	394	177	87
Manitoba	Midwest	N/A	2,412	30	0	1
Manitoba	Ontario	N/A	2,345	364	282	80
Midwest	Ontario	N/A	1,255	0	0	0
Ontario	NY/NJ	N/A	1,097	359	380	55
Ontario	Quebec	N/A	878	0	59	0
Quebec	New England	N/A	63	0	0	0
Transcontinental						
Southwest Central	South Atlantic	3,056	0	0	0	0
South Atlantic	Mid-Atlantic	2,362	0	0	0	0
Mid-Atlantic	NY/NJ	2,388	312	249	173	0
Transwestern						
Southwest Central	Pacific	750	0	340	0	0
Trunkline						
Southwest Central	South Atlantic	1,853	0	0	0	0
South Atlantic	Midwest	1,807	0	0	0	0
United						
Southwest Central	South Atlantic	950	0	0	0	0
Vermont Gas						
Quebec	New England	32	0	0	0	0
Viking						
Manitoba	Midwest	406	12	0	0	0
Williams						
Southwest Central	Central	673	0	0	0	0
North Central	Central	156	0	0	0	0

Table 11: Current Interstate and Intrastate Storage Capacity By Study Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
NEW YORK/NEW JERSEY REGION								
NEW YORK								
ADRIAN *	STEUBEN	STEUBEN	8,200	8,200	2,000	6,200	60	60 x
ALLEGANY STATE PARK*	NATIONAL FUEL	CATTARAUGUS	10,700	10,700	7,000	3,700	13	13
BENNINGTON	NATIONAL FUEL	ERIE	5,000	5,000	3,200	1,800	43	60
COLDEN	NATIONAL FUEL	ERIE	16,220	16,220	8,670	7,550	80	110
COLLINS	NATIONAL FUEL	ERIE	5,280	5,280	3,030	2,250	26	40
DERBY	NATIONAL FUEL	ERIE	250	250	0	250	5	5
DUNDEE	COLUMBIA	SCHUYLER, STEUBEN	11,360	11,360	7,860	3,500	56	56 x
EAST INDEPENDENCE *	PENN-YORK	ALLEGHENY	6,095	6,095	3,895	2,200	15	15
NORTH GREENWOOD	COLUMBIA	STEUBEN	3,200	3,200	2,950	250	1	1 x
SOUTH GREENWOOD	COLUMBIA	STEUBEN	3,725	3,725	3,325	400	6	6 x
HOLLAND	NATIONAL FUEL	ERIE	2,600	2,600	1,700	900	17	20
HONEOYE	HONEOYE	ONTARIO	8,710	8,710	3,913	4,797	40	40 x
LAWTONS	NATIONAL FUEL	ERIE	2,470	2,470	1,500	970	13	30
NASHVILLE	NATIONAL FUEL	CATTARAUGUS	8,530	8,530	4,600	3,930	52	110
PERRYSBURG	NATIONAL FUEL	CATTARAUGUS	3,850	3,850	2,000	1,850	34	40
SHERIDAN	NATIONAL FUEL	CHAUTAUQUA	3,700	3,700	2,600	1,100	15	25
BEECH HILL *	PENN-YORK	ALLEGHENY	17,791	17,791	7,891	9,900	51	66
TUSCARORA	NATIONAL FUEL	STEUBEN	6,300	6,300	2,500	3,800	57	80
WEST INDEP.	PENN-YORK	ALLEGHENY	11,595	11,595	4,295	7,300	35	49
WOODHULL	CNG	STEUBEN	35,904	35,904	17,428	18,476	357	357
ZOAR	NATIONAL FUEL	ERIE	2,200	2,200	1,600	600	32	60
TOTAL NEW YORK STORAGE			**173,680**	**173,680**	**91,957**	**81,723**	**1,008**	**1,243**
TOTAL STORAGE NEW YORK/NEW JERSEY REGION			**173,680**	**173,680**	**91,957**	**81,723**	**1,008**	**1,243**
			=======	=======	=======	=======	=======	=======
MID-ATLANTIC REGION								
MARYLAND								
ACCIDENT	TEXAS EASTERN	GARRETT	61,978	61,978	46,678	15,300	301	301
PENNSYLVANIA								
ARTEMUS A	COLUMBIA	BEDFORD	13,957	13,957	8,457	5,500	135	135 x
ARTEMUS B *	COLUMBIA	BEDFORD	2,100	2,100	1,250	850	18	18 x
BELMOUTH	NATIONAL FUEL	ELK	1,400	1,400	600	800	7	7

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
PENNSYLVANIA (Continued)								
BOONE MOUNTAIN	NATIONAL FUEL	ELK, CLEARFIELD	1,980	1,980	1,050	930	8	8
BUNOLA	EQUITRANS	ALLEGHENY, WASHINGTON	6,546	6,272	3,263	3,009	150	150 x
CORRY	NATIONAL FUEL	ERIE	600	600	400	200	20	40
DEERLICK	NATIONAL FUEL	WARREN	100	100	0	100		
DONEGAL	COLUMBIA	WASHINGTON	9,900	9,900	5,245	4,655	269	269 x
DUHRING	NATIONAL FUEL	FOREST	205	205	100	105	1	1
EAST BRANCH	NATIONAL FUEL	McKEAN, WARREN	13,380	13,380	8,880	4,500	31	35
ELLISBURG (1)	NATIONAL FUEL	POTTER	21,655	21,655	10,098	11,557	198	237
ELLISBURG (1)	CNG	POTTER	76,775	76,775	35,802	40,973	816	816
FINLEYVILLE	EQUITRANS	WASHINGTON	603	580	258	322	36	36 x
GALBRAITH	NATIONAL FUEL	JEFFERSON	1,620	1,620	720	900	14	16
GREENLICK	CNG	CLINTON, POTTER	55,860	55,860	33,040	22,820	900	900
HARRISON	CNG	POTTER	34,100	34,100	13,382	20,718	455	455
HEARD	COLUMBIA	GREENE, WASHINGTON	8,900	8,900	7,150	1,750	23	23 x
HEBRON	NATIONAL FUEL	POTTER	28,560	28,560	12,110	16,450	180	360
HENDERSON	NATIONAL FUEL	VENANGO, MERCER	3,900	3,900	1,900	2,000	36	36
HOLBROOK	COLUMBIA	GREENE	1,640	1,640	1,240	400	7	7 x
HUNTER'S CAVE	EQUITRANS	GREENE	4,033	3,755	2,403	1,352	18	18 x
KEELOR	NATIONAL FUEL	McKEAN	2,800	2,800	1,500	1,300	40	40
LEIDY-TAMARACK	CNG	POTTER	113,223	113,223	52,022	61,201	1,224	1,224
MAJORSVILLE-Shallow	COLUMBIA	WASHINGTON	3,483	3,483	2,083	1,400	32	32 x
MARKLE	NATIONAL FUEL	JEFFERSON	255	255	170	85	13	13
MEAKER	NORTH PENN	TIOGA	4,500	4,500	1,742	2,758	50	50 x
MUNDERF	COLUMBIA	JEFFERSON	55	55	43	12	0	
NORTH SUMMIT *	CNG	FAYETTE	23,000	23,000	11,500	11,500	100	300
OAKFORD	CNG	WESTMORELAND	123,176	123,176	62,416	60,760	775	775
OWL'S NEST	NATIONAL FUEL	ELK	2,200	2,200	1,550	650	7	7
PRATT	EQUITRANS	GREENE, WASHINGTON	7,253	7,253	4,753	2,500	25	25 x
QUEEN	NATIONAL FUEL	FOREST, WARREN	870	870	570	300	2	3

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
PENNSYLVANIA (Continued)								
SABINSVILLE	CNG	TIOGA	35,618	35,618	17,819	17,799	418	418
SHARON	CNG	POTTER	4,500	4,500	2,200	2,300	26	26
SOUTH BEND	CNG	INDIANA	17,340	17,340	11,530	5,810	173	173
ST. MARY'S	NATIONAL FUEL	ELK	420	420	250	170	1	1
SUMMIT	NATIONAL FUEL	ERIE	3,900	3,900	2,300	1,600	30	60
SWARTS	EQUITRANS	GREENE	992	992	497	495	14	14 x
SWARTS WEST	EQUITRANS	GREENE	1,356	1,356	922	434	14	14 x
SWEDE HILL	NATIONAL FUEL	McKEAN	1,000	1,000	700	300	5	8
TEPE	EQUITRANS	ALLEGHENY	945	940	222	718	35	35 x
TIOGA (Palmer) (2)	CNG	TIOGA	36,000	36,000	12,000	24,000	504	504
WELLENDORF	NATIONAL FUEL	McKEAN	975	975	525	450	7	7
WHARTON	NATIONAL FUEL	CAMERON	29,184	29,184	11,000	18,184	275	300
** COLVIN	THE PEOPLES NATURAL GAS	WASHINGTON	2,418	2,418	1,793	625	87	87
** GAMBLE-HAYDEN	COMPANY (PEOPLES	ALLEGHENY	2,849	2,843	2,199	644	36	36
** MURRYSVILLE	NATURAL)	ALLEGHENY	3,261	3,261	1,946	1,315	112	112
** PATTON	PEOPLES NATURAL	WESTMORELAND	161	148	85	63	8	8
** RAGER MTN.	PEOPLES NATURAL	CAMBRIA	21,393	19,079	11,193	7,886	102	102
** TRUITTSBURG	PEOPLES NATURAL	CLARION	3,691	3,642	2,191	1,451	102	102
** WEBSTER	PEOPLES NATURAL	WESTMORELAND	1,172	1,172	952	220	26	26
** ALABRAN	T. W. PHI GAS & OIL CO.	INDIANA	0	780	0	280	0	0
** BLACKHAWK	COLUMBIA OF PENN, INC.	BEAVER	2,500	0	0	0	0	0
** CLARK	T. W. PHILIPS GAS & OIL	INDIANA	0	963	0	325	0	0
** FAIR-HELM	COMPANY (T. W.	ARMSTRONG	0	120	0	36	0	0
** GOURLEY MILLER	PHILLIPS)	CLEARFIELD		283		100	0	0
** HUGHES	T. W. PHILLIPS	BUTLER	0	291	0	138	3	0
** KINTER	T. W. PHILLIPS	INDIANA	0	1,245	0	189	7	0
** PORTMAN	T. W. PHILLIPS	BUTLER	0	441	0	196	8	0
** SMITH-PARK	T. W. PHILLIPS	ALLEGHENY		182		33	1	1 x
** SPRANKLE	T. W. PHILLIPS	JEFFERSON	0	863	0	265	2	0
** VARDY	T. W. PHILLIPS	BUTLER		179		101	5	5 x
TOTAL PENNSYLVANIA STORAGE			**738,304**	**738,189**	**366,021**	**368,484**	**7,591**	**8,069**
WEST VIRGINIA								
AUGUSTA	HAMPSHIRE	HAMPSHIRE	6,625	6,625	4,477	2,148	47	47 x
BRIDGEPORT	CNG	HARRISON	9,139	8,221	5,173	3,048	82	82
BROWN'S CREEK	COLUMBIA	KANAWHA, PUTNAM	4,267	4,267	3,467	800	5	5 x

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
WEST VIRGINIA (Continued)								
CLEVELAND	COLUMBIA	RANDOLPH, UPSHUR	8,170	8,170	7,070	1,100	9	9 x
COCO A	COLUMBIA	KANAWHA	44,500	44,500	27,600	16,900	400	400 x
COCO B	COLUMBIA	KANAWHA	9,700	9,700	6,900	2,800	192	192 x
COCO C	COLUMBIA	KANAWHA	17,270	17,270	9,970	7,300	88	88 x
COMET	EQUITRANS	TAYLOR	5,159	5,131	2,361	2,770	53	53 x
DERRICK'S CREEK	COLUMBIA	KANAWHA	6,200	6,200	5,000	1,200	46	46 x
FINK-KENNEDY-LOST CREEK	CNG	HARRISON	161,572	153,572	100,498	53,074	925	925
GLADY	COLUMBIA	RANDOLPH, POCOHONTAS	30,000	30,000	21,200	8,800	259	259 x
GRAPEVINE A	COLUMBIA	KANAWHA	1,185	1,185	1,165	20	1	1 x
GRAPEVINE B	COLUMBIA	KANAWHA	78	78	70	8	1	1 x
HAYES	EQUITRANS	MARION	173	173	103	70	8	8 x
HUNT	COLUMBIA	KANAWHA	6,080	6,080	5,280	800	19	19 x
LAKE	COLUMBIA	PUTNAM	2,858	2,858	2,358	500	4	4 x
LANHAM	COLUMBIA	KANAWHA, PUTNAM	4,800	4,800	3,600	1,200	79	79 x
LITTLE CAPON	HAMPSHIRE	HAMPSHIRE	7,356	7,356	4,916	2,440	53	43 x
LOGANSPORT	EQUITRANS	MARION	3,459	3,459	1,193	2,266	32	32 x
MAJORSVILLE-Deep	COLUMBIA	GREENE, MARSHALL	24,523	24,523	16,723	7,800	73	73 x
MAPLE LAKE	EQUITRANS	TAYLOR, HARRISON	2,540	1,878	1,026	852	10	10 x
MOBLEY	EQUITRANS	WETZEL	7,141	7,141	3,158	3,983	51	51 x
RACKET-NEWBERNE	CNG	RITCHIE, GILMER	9,645	7,911	4,811	3,100	80	80
RALEIGH	CRANBERRY	RALEIGH	2,600	2,600	163	2,437		
RHODES A,B,C	EQUITRANS	LEWIS	8,323	7,938	4,411	3,527	39	39 x
RIPLEY	COLUMBIA	JACKSON	23,400	23,400	15,150	8,250	182	182 x
ROCKPORT	COLUMBIA	JACKSON, WOOD WIRT	8,160	8,160	5,260	2,900	136	136 x
SHIRLEY	EQUITRANS	TAYLOR, DODDRIDGE	11,000	11,000	6,301	4,699	62	62 x
SISSONVILLE	COLUMBIA	KANAWHA	1,248	1,248	1,198	50	1	1 x
SKIN CREEK	EQUITRANS	LEWIS	1,652	1,652	778	874	28	28 x

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
WEST VIRGINIA (Continued)								
TERRA ALTA	COLUMBIA	PRESTON	40,163	40,163	31,863	8,300	149	149 x
TERRA ALTA S	COLUMBIA	PRESTON	16,600	16,600	13,800	2,800	61	61 x
VICTORY A	COLUMBIA	WETZEL, MARSHALL	7,150	7,150	4,350	2,800	59	59 x
VICTORY B	COLUMBIA	WETZEL, MARSHALL	24,000	24,000	14,700	9,300	143	143 x
X-1 (Heizer)	CRANBERRY	PUTNAM	4,270	4,270	268	2,222		
TOTAL WEST VIRGINIA			521,006	509,279	336,361	171,138	3,377	3,367
TOTAL STORAGE MID-ATLANTIC REGION			1,321,288	1,309,446	749,060	554,922	11,269	11,737
			=========	=========	=========	=========	=========	=========
SOUTH ATLANTIC REGION								
KENTUCKY								
** BON HARBOR	WESTERN KENTUCKY GAS CO.	DAVIESS	2,077	2,079	1,300	777	21	21 x
** CENTER	LOUISVILL GAS & ELEC. CO.	METCALFE GREEN BARREN	5,106	5,106	2,720	2,386		50
** DIXIE	TEXAS GAS	HENDERSON	7,257	7,257	4,982	2,575		101
** DOE RUN UPPER	LOUISVILL GAS & ELEC. CO.	MEADE	5,787	5,787	1,810	3,977	100	100 x
** EAST SLAUGHTERS	ALCAN ING & RECYCLING	HOPKINS	767	534	138	396		0
** GRAHAM LAKE	TEXAS GAS	MUHLENBERG	4,284	4,284	2,958	1,326		15
** GRAND VIEW	WESTERN KENTUCKY GAS CO.	DAVIESS	647	648	350	297	2	2 x
** HANSON	TEXAS GAS	HOPKINS	12,087	12,087	8,160	3,927		71
** HICKORY SCHOOL	WESTERN KENTUCKY GAS CO.	DAVIESS	1,294	1,303	850	444	19	19 x
** KETTLE ISLAND	DELTA NATURAL GAS CO.	BELL	1,406	971	785	186	2	2 x
** KIRKWOOD SPRINGS	WESTERN KENTUCKY GAS CO.	HOPKINS	607	625	400	207	10	10 x
** LAUREL	ELIZABETH NATURAL GAS	HARDIN	875	744	490	254	1	1 x
** LEGO	ELIZABETH NATURAL GAS	HARDIN	2,128	2,012	500	1,512	3	3 x
** MAGNOLIA DEEP	LOUISVILL GAS & ELEC. CO.	HART, GREEN LARUE	4,426	4,426	2,370	2,056	45	45 x
** MAGNOLIA UPPER	LOUISVILL GAS & ELEC. CO.	HART, GREEN LARUE	5,949	5,949	2,460	3,489	75	75 x
** MIDLAND	TEXAS GAS	MUHLENBERG	133,142	133,142	64,474	68,668		883
** MULDRAUGH	LOUISVILL GAS & ELEC. CO.	MEADE	4,249	4,249	1,450	2,799	215	215 x
** OWENSBORO	WESTERN KENTUCKY GAS CO.	DAVIESS	61	61	41	20	2	2 x

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
KENTUCKY (Continued)								
** ST. CHARLES	WESTERN KENTUCKY GAS CO.	HOPKINS	6,937	6,590	3,470	3,467	36	36 x
** WEST GREENVILLE	TEXAS GAS	MUHLENBERG	7,650	7,650	4,264	3,386		101
TOTAL KENTUCKY STORAGE			**206,736**	**205,504**	**103,972**	**102,149**	**531**	**1,752**
MISSISSIPPI								
EMINENCE SALT CAVERN	TRANSCO	COVINGTON	20,500	20,500	5,500	15,000	1,500	1,500
JACKSON	UNITED	RANKIN, HINDS	5,550	5,550	2,824	2,726	250	250
MULDON	SOUTHERN	MONROE	92,820	92,820	40,820	52,000	750	750
** AMORY	MISSISSIPPI VALLEY GAS CO.	MONROE	1,500	1,462	318	1,144	14	14 x
** HATTIESBURG SALT DOME	FIRST RESERVE CORP.	LAMAR				3,500	350	350
TOTAL MISSISSIPPI STORAGE			**120,370**	**120,332**	**49,462**	**74,370**	**2,864**	**2,864**
TOTAL STORAGE SOUTH ATLANTIC REGION			**327,106**	**325,836**	**153,434**	**176,519**	**3,395**	**4,616**
			=======	=======	=======	=======	=======	=======
MIDWEST REGION								
ILLINOIS								
COOK MILLS	NGPL	DOUGLAS, COLES	5,200	5,200	1,600	3,600	60	60
HERSCHER GALESVILLE	NGPL	KANAKEE	37,000	37,000	23,200	13,800	790	960
HERSCHER MT SIMON *	NGPL	KANAKEE	67,000	67,000	32,300	34,700	180	288
HERSCHER NORTHWEST *	NGPL	KANAKEE	18,500	18,500	13,700	4,800	65	65
LOUDON	NGPL	FAYETTE	80,000	80,000	42,900	37,100	400	450
ST. JACOB	MRT	MADISON	5,600	4,100	3,400	700	30	30
WAVERLY *	PANHANDLE	MORGAN, SANGAMON	55,000	55,000	44,400	10,600	70	220
** ANCONA-GARFIELD	NORTHERN ILLINOIS GAS CO.	LIVINGSTON, LA SALLE	170,000	170,000	102,500	67,500	850	850
** ASHMORE SOUTH	CENTRAL ILL PUB. SERV.	COLES, CLARK	3,599	3,578	1,981	1,597	32	32 x
** CENTRALIA EAST	ILLINOIS POWER COMPANY	MARION	615	615	473	142	14	14 x
** CORINTH/ CRAB ORCHARD	CENTRAL ILL PUB. SERV.	WILLIAMSON	267	265	72	193	2	2 x
** EDEN SOUTH	ILLINOIS POWER COMPANY	RANDOLPH	1,403	1,403	1,013	390	8	8 x
** FREEBURG	ILLINOIS POWER COMPANY	ST.CLAIR	6,936	6,936	5,036	1,900	35	35 x
** GILLESPIE	ILLINOIS POWER COMPANY	MACOUPIN	147	147	115	32	5	5 x
** GLASFORD	CENTRAL ILLINOIS LIGHT CO.	PEORIA	11,600	11,400	5,800	5,600	200	200 x

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
ILLINOIS (Continued)								
** HILLSBORO	ILLINOIS POWER COMPANY	MONTGOMERY	10,214	10,214	7,114	3,100	40	40 x
** HOOKDALE	ILLINOIS POWER COMPANY	BOND	996	996	285	711	25	25 x
** HUDSON	NORTHERN ILLINOIS GAS CO.	MCLEAN	100,000	100,000	88,600	11,400	150	150
** LAKE BLOOMINGTON	NORTHERN ILLINOIS GAS CO.	MCLEAN	55,000	55,000	40,500	14,500	150	150
** LEXINGTON	NORTHERN ILLINOIS GAS CO.	MCLEAN	100,000	100,000	87,300	12,700	125	125
** LINCOLN	CENTRAL ILLINOIS LIGHT CO.	LOGAN	12,200	10,000	6,710	3,290	85	85 x
** MANLOVE	PEOPL GAS LIGHT AND COKE	CHAMPAIGN	136,649	133,299	93,216	40,084	673	673 x
** PECATONICA	NORTHERN ILLINOIS GAS CO.	WINNEBAGO	3,500	3,500	2,200	1,300	40	40
** PONTIAC	NORTHERN ILLINOIS GAS CO.	LIVINGSTON	21,000	21,000	15,500	5,500	200	200
** PONTIAC-MT. SIMON	NORTHERN ILLINOIS GAS CO.	LIVINGSTON	45,000	45,000	28,100	16,900	40	40
** RICHWOODS	CENTRAL ILL PUB. SERV.	CRAWFORD	120	118	15	103	1	1 x
** SCIOTA	CENTRAL ILL PUB. SERV.	MCDONOUGH	5,000	4,306	2,861	1,445	25	25 x
** SHANGHAI	ILLINOIS POWER COMPANY	WARREN MERCER	11,612	11,612	6,007	5,605	76	76 x
** TILDEN	ILLINOIS POWER COMPANY	ST. CLAIR WASHINGTON	2,689	2,689	1,819	870	50	50 x
** TROY GROVE	NORTHERN ILLINOIS GAS CO.	LASALLE	80,000	80,000	38,500	41,500	850	850
TOTAL ILLINOIS STORAGE			**1,046,847**	**1,038,878**	**697,217**	**341,662**	**5,271**	**5,749**
INDIANA								
ALFORD	TEXAS GAS	PIKE	2,518	2,518	1,530	988	40	40
CALCUTTA-CARBON *	MIDWEST	CLAY, PARKE	4,540	4,540	1,600	2,940	27	27 x
LEESVILLE	TEXAS GAS	LAWRENCE	4,774	4,774	2,126	2,648	40	40
OAKTOWN	TEXAS GAS	KNOX	1,052	1,052	429	623	9	9
WHITE RIVER	TEXAS GAS	PIKE, KNOX	510	510	204	306	5	5
WILFRED	TEXAS GAS	SULLIVAN	3,417	3,417	1,224	2,193	37	37
** DIXON	CITIZENS GAS & COKE	GREENE	2,780	2,780	1,911	869	50	50 x
** GLENDALE	HOOSIER GAS CORP.	DAVIESS	346	272	215	57	2	2 x
** GREENSBURG	INDIANA GAS CO., INC.	DECATUR	1,178	1,178	700	478	1	1 x
** HOWESVILLE	CITIZENS GAS & COKE	GREENE	4,400	4,250	3,200	1,050	80	80 x
** LAWRENCEBURG STORAGE	LAWRENCEBURG GAS CO.	DEARBORN	20	20	7	13	1	1 x
** LOOGOOTEE	HOOSIER GAS CORP.	DAVIESS	221	221	103	118	1	1 x
** MIDWAY	SOUTHERN INDIANA G&E	SPENCER	4,319	4,319	1,304	3,015	50	50 x
** MINERAL CITY	CITIZENS GAS & COKE	GREENE	2,083	2,083	1,683	400	13	13 x

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
INDIANA (Continued)								
** MONROE CITY	HOOSIER GAS CORP.	KNOX	4,523	4,523	3,167	135	23	23 x
** OLIVER	SOUTHERN INDIANA G&E	POSEY	3,805	3,805	1,741	2,064	48	48 x
** ROYAL CENTER	NORTHERN IND. PUB. SERVICE	FULTON	15,049	15,595	14,532	1,063	100	100 x
** ROYAL CENTER	NORTHERN IND. PUB. SERVICE	CASS	16,521	14,038	10,574	3,464	180	180 x
** SELLERSBURG	INDIANA GAS CO., INC.	CLARK	1,343	1,343	1,200	143	12	12 x
** SIMPSON CHAPEL	CITIZENS GAS & COKE	GREENE	2,200	2,200	1,800	400	12	12 x
** SWITZ CITY	CITIZENS GAS & COKE	GREENE	5,635	5,635	4,778	857	20	20 x
** UNIONPORT NORTH	INDIANA GAS CO., INC.	RANDOLPH	1,100	1,077	1,001	76	20	20 x
** UNIONPORT SOUTH	INDIANA GAS CO., INC.	RANDOLPH	500	493	432	61	5	5 x
** UNIONVILLE	INDIANA GAS CO., INC.	MONROE	0	488	423	65	0	
** UNIONVILLE	INDIANA GAS CO., INC.	MONROE	6,275	6,275	3,000	3,275	64	64 x
** WEST POINT	INDIANA GAS CO., INC.	TIPPECANOE	1,027	1,027	770	257	9	9 x
** WOLCOTT	INDIANA GAS CO., INC.	WHITE	7,020	3,591	3,204	387	0	
** WOLCOTT	INDIANA GAS CO., INC.	WHITE	0	7,020	4,500	2,520	61	61 x
** WORTHINGTON	CITIZENS GAS & COKE	GREENE	13,200	13,200	9,684	3,516	50	50 x
TOTAL INDIANA STORAGE			**110,356**	**112,244**	**77,042**	**33,981**	**960**	**960**
MICHIGAN								
AUSTIN	ANRPL	MECOSTA	23,323	21,323	11,323	10,000	800	800
BELLE RIVER MILLS	MICHCON	ST. CLAIR	75,704	75,704	29,017	46,687	1,500	1,630
CAPAC *	ANRPL	ST. CLAIR, LAPEER	42,220	42,220	20,220	22,000	70	175
CENTRAL CHARLTON 1	ANRPL	OSTEGO	19,000	19,000	2,700	16,300	200	220
COLD SPRINGS 12	ANRSC	KALASKA	27,227	27,227	3,627	23,600	295	300
COLD SPRINGS 31	ANRSC	KALASKA	5,734	5,734	747	4,987	68	75
COLDWATER	ANRPL	ISABELLA	12,988	10,488	5,488	5,000	5	28
COLUMBUS	MICHCON	ST. CLAIR	17,504	17,504	2,586	14,918	300	523
CROTON	ANRPL	NEWAYGO	5,357	5,057	2,557	2,500	7	45
ECCELSIOR 6/ EAST KALASKA	ANRSC	KALASKA	11,089	11,089	1,500	9,589	120	125
GOODWELL	ANRPL	NEWAYGO	29,625	29,625	4,925	24,700	122	300
HOWELL	PANHANDLE	LIVINGSTON	32,000	32,000	15,900	16,100	360	360
LINCOLN-FREEMAN	ANRPL	CLARE	35,440	35,440	16,440	19,000	185	320
LOREED	ANRPL	OSCEOLA	48,210	48,210	17,210	31,000	125	640
MUTTONVILLE	ANRPL	MACOMB	13,387	13,387	2,287	11,100	400	400
NEW HAVEN	MICHCON	MONTCALM	15,912	15,912	9,348	6,564	50	58
NORTH HAMILTON	ANRPL	CLARE	12,141	12,141	8,641	3,500	5	50

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
MICHIGAN (Continued)								
NORWICH	ANRPL	NEWAYGO	8,410	8,410	5,210	3,200	5	50
ORIENT	ANRPL	OSCEOLA	9,806	9,105	4,605	4,500	6	60
RAPID RIVER 35	ANRSC	KALASKA	16,976	16,976	2,276	14,700	190	250
REED CITY	ANRPL	OSCEOLA	28,591	28,591	12,591	16,000	65	300
RIVERSIDE	MICHIGAN GAS	MISSAUKEE	12,000	12,000	7,500	4,500	37	37
SOUTH CHESTER 15	ANRPL	OSTEGO	19,665	19,665	2,865	16,800	200	270
TAGGART	MICHCON	MECOSTA, MONTCALM	80,881	80,881	41,100	39,781	500	560
WASHINGTON 28	MICHCON	MACOMB	11,500	11,500	1,900	9,600	100	200
WEST COLUMBUS	MICHCON	ST. CLAIR	25,759	25,759	3,879	21,880	400	452
WINFIELD	ANRPL	MONTCALM	14,470	14,074	6,674	7,400	35	60
WINTERFIELD/ CRANBERRY LAKE	MICHIGAN GAS	CLARE, OSCEOLA	105,000	105,000	65,000	40,000	480	480
** CAMBELL	MICHIGAN GAS UTILITIES CO.	CALHOUN	785	785	608	177		
** COLLINS FIELD	SOUTHEAST MICHIGAN GAS CO.	ST. CLAIR	3,410	2,520	493	2,027	25	25 x
** CORTRIGHT	MICHIGAN GAS UTILITIES CO.	CALHOUN	1,125	1,125	752	373	12	14
** FOUR CORNERS	CONSUMERS POWER	ST.CLAIR	3,780	2,405	1,390	1,015	13	13 x
** HARRIS STORAGE	BATTLE CREEK GAS CO.	CALHOUN	1,127	728	290	438	7	7 x
** HESSEN	CONSUMERS POWER	ST.CLAIR	17,980	10,153	6,907	3,246	100	100 x
** IRA	CONSUMERS POWER	ST.CLAIR	7,500	6,212	3,500	2,712	250	250 x
** LACEY SALT STORAGE	BATTLE CREEK GAS CO.	BARRY	290	242	30	212	25	25 x
** LENOX	CONSUMERS POWER	MACOMB	3,500	3,019	2,000	1,019	200	200 x
** MORTON (6 RESERVOIRS)	SOUTHEAST MICHIGAN GAS CO.	ST. CLAIR	4,245	3,410	1,122	2,288	50	50 x
** NORTHVILLE	CONSUMERS POWER	WAYNE,WASHTENAW WASHTENAW, OAKLAND	22,412	13,561	13,412	149	25	25 x
** NORTHVILLE	CONSUMERS POWER	WASHTENAW	1,780	1,232	720	512	50	50 x
** OVERISEL	CONSUMERS POWER	ALLEGAN	64,000	50,688	40,000	10,688	200	200 x
** PARTELLO/ ANDERSON	MICHIGAN GAS UTILITIES CO.	CALHOUN	4,967	4,967	3,541	1,426	19	19
** PUTTYGUT	CONSUMERS POWER	ST. CLAIR	16,600	13,692	7,580	6,112	250	250 x
** RAY	CONSUMERS POWER	MACOMB	66,000	57,146	22,000	35,146	100	100 x
** SALEM	CONSUMERS POWER	ALLEGAN	35,000	30,452	23,000	7,452	100	100 x
** SWAN CREEK	CONSUMERS POWER	ST. CLAIR	650	360	230	130	13	13 x
TOTAL MICHIGAN STORAGE			**1,015,070**	**956,719**	**435,691**	**521,028**	**8,069**	**10,209**

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
MINNESOTA								
** WATERVILLE/ WASECA	MINNEGASCO INC.	WASECA, RICE, LE SUEUR	20,000	6,700	4,600	6,700	60	60 x
OHIO								
BENTON	COLUMBIA	HOCKING, VINTON	25,100	25,100	16,900	8,200	138	138 x
BRINKER	COLUMBIA	COLUMBIANA	7,650	7,650	5,250	2,400	43	43 x
CRAWFORD *	COLUMBIA	FAIRFIELD, HOCKING	118,600	50,000	35,435	14,565	140	140 x
GUERNSEY	COLUMBIA	GUERNSEY, COSHOCTON	7,300	7,300	5,600	1,700	36	36 x
HOLMES	COLUMBIA	HOLMES, WAYNE	21,700	21,700	16,870	4,830	42	42 x
LAUREL	COLUMBIA	HOCKING	23,300	23,300	14,900	8,400	111	111 x
LORAIN	COLUMBIA	LORAIN	10,700	10,700	8,700	2,000	90	90 x
LUCAS	COLUMBIA	ASHLAND	60,400	60,400	38,500	21,900	277	277 x
McARTHUR	COLUMBIA	VINTON	10,900	10,900	6,100	4,800	107	107 x
MEDINA	COLUMBIA	MEDINA	10,400	10,400	8,900	1,500	60	60 x
PAVONIA	COLUMBIA	ASHLAND, RICHLAND	49,500	49,500	30,200	19,300	287	287 x
WAYNE	COLUMBIA	ASHLAND, HOLMES, WAYNE	17,400	17,400	13,300	4,100	119	119 x
WEAVER	COLUMBIA	ASHLAND, KNOX	50,500	50,500	35,486	15,014	230	230 x
WELLINGTON	COLUMBIA	LORAIN, MEDINA	23,100	23,100	17,800	5,300	125	125 x
ZANE	COLUMBIA	MUCKINGUM	145	145	105	40	1	1 x
** CHIPPEWA	THE EAST OHIO GAS CO.	WAYNE	11,475	11,475	9,654	1,821	469	484
** COLUMBIANA	THE EAST OHIO GAS CO.	COLUMBIANA	3,111	3,111	1,948	1,163	8	8
** GABOR	THE EAST OHIO GAS CO.	WAYNE	3,793	3,793	3,488	305	108	108
** MUSKIE	NATIONAL GAS & OIL CORP.	MUSKINGUM	1,400	969	724	245	4	4 x
** PERRY	NATIONAL GAS & OIL CORP.	PERRY	4,973	2,873	1,900	973	30	30 x

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
OHIO (Continued)								
** STARK-SUMMIT	THE EAST OHIO GAS CO.	STARK SUMMIT	147,634	147,634	94,329	53,305	1,001	1,069
** ZANE	NATIONAL GAS & OIL CORP.	MUSKINGUM	2,295	1,209	900	309	6	6 x
TOTAL OHIO STORAGE			611,376	539,159	366,989	172,170	3,432	3,515
TOTAL STORAGE MIDWEST REGION			2,803,649	2,653,700	1,581,539	1,075,541	17,792	20,493
			=========	=========	=========	=========	=========	=========
CENTRAL REGION								
IOWA								
CAIRO GALESVILLE *	NGPL	LOUISA	24,700	15,600	6,600	9,000	54	54
CAIRO MT. SIMON	NGPL	LOUISA	62,100	50,700	27,700	23,000	169	169
CAIRO ST PETER	NGPL	LOUISA	27,000	27,000	18,100	8,900	145	145
COLUMBUS CITY/ MT. SIMON	NGPL	LOUISA	49,400	39,100	20,100	19,000	117	117
COLUMBUS CITY/ ST. PETER	NGPL	LOUISA	16,300	14,100	7,900	6,200	49	49
KEOTA	NGPL	WASHINGTON	6,000	6,000	3,100	2,900	50	50
REDFIELD	NORTHERN	DALLAS	120,000	120,000	86,500	33,500	223	418
TOTAL IOWA STORAGE			305,500	272,500	170,000	102,500	807	1,002
KANSAS								
ADOLPH	K N	BARTON	5,845	5,845	3,445	2,400	8	8
ALDEN	WILLIAMS	RICE	15,900	15,771	10,771	5,000	130	175
BOEHM *	CIG	MORTON	24,800	22,300	15,900	6,400	96	96
COLLINSON	ARKLA	COWLEY	2,393	2,393	1,260	1,133	7	10
COLONY	WILLIAMS	ANDERSON	12,730	12,730	7,276	5,454	170	175
CRAIG	WILLIAMS	JOHNSON	6,043	6,043	5,513	530	55	61
CUNNINGHAM *	NORTHERN	PRATT, KINGMAN	71,000	71,000	26,000	45,000	300	500
ELK CITY	WILLIAMS	ELK	21,881	21,881	16,073	5,808	275	302
LYONS *	NORTHERN	RICE	36,000	36,000	18,000	18,000	90	120
McLOUTH *	WILLIAMS	JEFFERSON	19,991	19,991	11,973	8,018	225	225
PIQUA	WILLIAMS	ALLEN, WOODSON	3,213	3,213	3,084	129	17	17
WELDA (N)	WILLIAMS	ANDERSON	15,117	15,117	11,992	3,125	140	145
WELDA (S)	WILLIAMS	ANDERSON	18,300	18,300	12,881	5,419	172	180
** BORCHERS NORTH	PANHANDLE	MEADE	70,100	70,100	35,100	35,000		350
** BUFFALO	UNION GAS SYSTEM, INC	WILSON	5,605	2,938	704	2,234		0

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
KANSAS (Continued)								
** FREDONIA	UNION GAS SYSTEM, INC	WILSON	0	0	0	0		0
** LIBERTY NORTH	UNION GAS SYSTEM, INC	MONTGOMERY	0	0	0	0		0
** LIBERTY SOUTH	UNION GAS SYSTEM, INC	MONTGOMERY	0	0	0	0		0
TOTAL KANSAS STORAGE			328,918	323,622	179,972	143,650	1,685	2,364
NEBRASKA								
BIG SPRINGS	K N	DEUEL	53,843	53,843	14,843	39,000	120	120
HUNTSMAN	K N	CHEYENNE	39,469	39,469	12,469	27,000	101	101
TOTAL NEBRASKA STORAGE			93,312	93,312	27,312	66,000	221	221
TOTAL STORAGE CENTRAL REGION			727,730	689,434	377,284	312,150	2,713	3,587
			=======	=======	=======	=======	=======	=======
SW CENTRAL REGION								
ARKANSAS								
** JETHRO	ARKANSAS WESTERN GAS CO.	FRANKLIN	38,000	34,323	22,000	12,323	100	100 x
** LAVACA DEEP(A)	ARKANSAS OKLAHOMA GAS	SEBASTIAN	3,353	3,353	3,290	63	12	12 x
** LONE ELM	ARKANSAS WESTERN GAS CO.	FRANKLIN	16,780	16,780	15,780	1,000	35	35 x
** WATALULA	ARKANSAS WESTERN GAS CO.	FRANKLIN	7,722	7,722	6,722	1,000	35	35 x
** WHITE OAK	ARKANSAS WESTERN GAS CO.	FRANKLIN	6,943	6,943	5,943	1,000	35	35 x
TOTAL ARKANSAS STORAGE			72,798	69,121	53,735	15,386	217	217
LOUISIANA								
BEAR CREEK	BEAR CREEK	BIENVILLE	114,900	114,900	49,900	65,000	900	900
BISTINEAU	UNITED	BIENVILLE, BOSSIER	141,000	141,000	72,200	68,800	1,200	1,200
EAST UNIONVILLE	MRT	LINCOLN	55,200	55,200	38,853	16,347	400	400
EPPS & SOUTH EPPS *	TRUNKLINE	E. CARROLL, W. CARROLL	63,423	63,423	38,423	25,000	200	250
HESTER *	TRANSCO	ST. JAMES	23,500	23,500	11,500	12,000	100	100
RUSTON	ARKLA	LINCOLN	11,000	5,700	3,500	2,200	60	60
WASHINGTON *	TRANSCO	ST. LANDRY	120,000	120,000	45,000	75,000	800	800
WEST UNIONVILLE	MRT	LINCOLN	69,000	27,100	12,253	14,847	250	250
** SORRENTO	BRIDGELINE	ASCENSION	10,000	10,000	4,000	6,000		320
TOTAL LOUISIANA STORAGE			608,023	560,823	275,629	285,194	3,910	4,280

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
OKLAHOMA								
ADA	ARKLA	PONTOTOC	24,152	24,152	14,652	9,500	300	300
CHILES DOME	ARKLA	COAL	26,000	26,000	14,000	12,000	266	266
ENFISCO GAS STORAGE	PHILLIPS	OSAGE	2,150	2,150	1,618	532	3	3
NORTH HOPETON *	PANHANDLE	WOODS	21,600	21,600	11,600	10,000	75	100
SAYRE	NGPL	BECKHAM	90,300	90,300	44,000	46,300	350	400
WEBB	WILLIAMS	GRANT	55,298	55,298	30,681	24,617	165	275
** DEPEW	OKLAHOMA NATURAL GAS CO.	CREEK	59,046	48,188	37,147	11,041	500	500 x
** GREASY CREEK	TRANSOK PIPELINE	HUGHES	27,200	18,236	2,635	15,601	200	200 x
** HASKELL	OKLAHOMA NATURAL GAS CO.	MUSKOGEE	13,924	12,527	9,610	2,917	40	40 x
** OSAGE	OKLAHOMA NATURAL GAS CO.	OSAGE	3,183	2,644	1,892	752	60	60 x
** OSWEGO LIME	ZCA GAS GATHERING CO. INC.	OSAGE	501	295	180	115		5
** WEST EDMOND	OKLAHOMA NATURAL GAS CO.	LOGAN, KINGFISHER	48,300	38,539	30,334	8,205	350	350 x
TOTAL OKLAHOMA STORAGE			**371,654**	**339,929**	**198,349**	**141,580**	**2,309**	**2,499**
NEW MEXICO								
WASHINGTON RANCH *	EL PASO	EDDY	68,600	44,100	20,000	24,100	250	500
** GRAMMA RIDGE	LLANO INC	LEA	13,260	2,364	0	2,364	50	50 x
** LAS MILPAS	GAS COMP. OF NEW MEXICO	SANDOVAL	13,260	7,242	0	7,242		0
TOTAL NEW MEXICO STORAGE			**95,120**	**53,706**	**20,000**	**33,706**	**300**	**550**
TEXAS								
CLEAR LAKE WEST	EXXON	HARRIS	125,000	125,000	32,963	92,038		
CLEMENS SALT DOME 20	PHILLIPS	BRAZORIA	2,850	2,850	712	2,138	19	19 x
LAKE DALLAS	LONE STAR	DENTON	4,575	4,575	1,853	2,722	70	70 x
NEW YORK	LONE STAR	CLAY	7,559	7,559	2,133	5,426	65	65 x
NORTH LANSING	NGPL	HARRISON	156,000	156,000	81,500	74,500	950	950
** AMBASSADOR	LONE STAR GAS	CLAY	2,268	1,693	657	1,036	40	40 x
** BAMMEL	HOUSTON PIPELINE	HARRIS	118,000	118,000	46,000	72,000	1,000	1,200
** BETHEL SALT DOME NO. 1	TEXAS UTILITIES FUEL CO.	ANDERSON	3,350	3,350	1,710	1,640	1	1 x
** BETHEL SALT DOME NO. 3	TEXAS UTILITIES FUEL CO.	ANDERSON	4,840	4,840	2,470	2,370	1	1 x
** BETHEL SALT DOME NO. 2A	TEXAS UTILITIES FUEL CO.	ANDERSON	4,150	4,150	2,060	2,090	1	1 x

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
TEXAS (Continued)								
** BOLING SALT DOME	VALERO ENERGY CORP.	WHARTON	9,700	9,014	3,000	6,014		
** HILL	LONE STAR GAS	EASTLAND	10,806	9,159	2,238	6,921	95	95 x
** LAPAN	LONE STAR GAS	CLAY	4,670	2,314	1,065	1,249	110	110 x
** LEERAY	LONE STAR GAS	STEPHENS	6,912	4,614	2,163	2,451	20	20 x
** LONE CAMP	SOUTHWEST GAS P/L INC.	PALO PINTO	1,066	526	353	173	20	20 x
** LOOP	CABOT STORAGE CORP.	GAINES	8,300	5,086	2,568	2,519	50	50 x
** MOSS BLUFF	TEXAS POWER	LIBERTY	1,800	1,800	450	1,350	150	150
** PECAN STATION	LONE STAR GAS	TOM GREEN	2,197	1,775	895	880	38	38 x
** PICKTON	DELHI PIPELINE	HOPKINS	20,000	20,000	15,130	4,870		27
** POTTSVILLE SOUTH	LONE STAR GAS	HAMILTON	8,702	7,258	4,550	2,708	21	21 x
** ROTHERWOOD	EASTEX ENERGY	HARRIS	1,500	1,500	500	1,000		70
** SOUTH BRYSON (STRAWN 1)	TEXAS UTILITIES FUEL CO.	JACK, YOUNG	8,000	8,000	3,000	5,000	200	200 x
** SPINDLETOP	GULF STATES	JEFFERSON	10,000	10,000	3,000	7,000		250
** STRATTON RIDGE	AMOCO GAS	BRAZORIA	1,500	1,500	500	1,000		150
** STRATTON RIDGE	DOW PIPELINE	BRAZORIA	10,000	10,000	3,000	7,000		200
** TRI-CITIES	LONE STAR GAS	HENDERSON	10,717	5,510	2,735	3,723	68	68 x
** TRI-CITIES SOUTH	LONE STAR GAS	HENDERSON	28,245	23,934	7,161	16,773	257	257
** VIEW	LONE STAR GAS	TAYLOR	4,774	1,660	1,541	119	26	26 x
** WORSHAM-STEED	TEXAS UTILITIES FUEL CO.	JACK	22,000	15,913	3,083	12,830	120	120 x
TOTAL TEXAS STORAGE			599,481	567,580	228,990	339,540	3,322	4,219
TOTAL STORAGE SOUTHWEST CENTRAL REGION			1,747,076	1,591,159	776,703	815,406	10,058	11,765
			=========	=========	=========	=========	=========	=========
NORTH CENTRAL REGION								
COLORADO								
FLANK	CIG	BACA	20,000	18,200	11,040	7,160	120	120
FORT MORGAN *	CIG	MORGAN	14,322	14,322	6,962	7,360	350	350
LATIGO	CIG	ARAPAHOE	22,400	21,500	13,400	8,100	120	120
SPRINGDALE	K N	LOGAN	5,692	5,692	2,402	3,290	12	12
** ASBURY	WESTERN GAS SUPPLY CO.	MESA	4,241	4,241	1,224	3,017	16	16 x
** FRUITA	WESTERN GAS SUPPLY CO.	MESA	318	308	38	270	1	1 x
** LEYDEN MINE	PUB. SERV CO. OF COLORADO	JEFFERSON	3,004	3,004	794	2,210	185	185 x
** MESA VERDE	ROCKY MTN NAT GAS	PITKIN	3,000	3,000	1,636	1,364	25	25 x
** ROUNDUP	WESTERN GAS	MORGAN	14,606	14,606	10,106	4,500	50	50
** WOLF CREEK	GASCO	PITKIN	14,500	14,500	7,450	7,050	10	15
TOTAL COLORADO STORAGE			102,083	99,373	55,052	44,321	889	894

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
MONTANA								
BAKER	WILLISTON	FALLON	287,200	287,200	124,092	163,108	124	124 x
** BOX ELDER	MONTANA POWER CO.	BAINE & HILL	9,103	6,905	2,482	4,423	11	11 x
** COBB	MONTANA POWER CO.	GLACIER & TOOLE	37,384	36,336	28,025	8,311	125	125 x
** DRY CREEK	MONTANA POWER CO.	CARBON	27,810	27,810	17,243	10,567	32	32 x
** SHELBY	MONTANA POWER CO.	TOOLE	2,450	2,450	1,186	1,264	6	6 x
TOTAL MONTANA STORAGE			363,947	360,701	173,028	187,673	298	298
UTAH								
BRIDGER LAKE	PHILLIPS	SUMMIT	3,000	3,000	1,618	1,382	10	10 x
CHALK CREEK	QUESTAR	SUMMIT	1,980	1,980	1,705	275	26	50
CLAY BASIN *	QUESTAR	DAGGETT	100,000	80,000	50,000	30,000	400	450
COALVILLE *	QUESTAR	SUMMIT	10,000	3,200	2,400	800	75	75 x
TOTAL UTAH STORAGE			114,980	88,180	55,723	32,457	511	585
WYOMING								
BILLY CREEK	WILLISTON	JOHNSON	2,944	2,944	2,402	542	11	11 x
ELK BASIN	WILLISTON	PARK	63,205	63,205	33,507	29,698	55	55 x
LEROY *	QUESTAR	UINTA	10,000	6,355	5,105	1,250	64	85
** BUNKER HILL	NORTHERN GAS CO.	CARBON	5,500	5,500	4,050	1,478	8	8 x
** KIRK FIELD	NORTHERN GAS CO.	FREMONT	2,020	2,020	1,440	580	4	4 x
** OIL SPRINGS	NORTHERN GAS CO.	CARBON	22,200	22,200	12,500	9,700	30	30 x
TOTAL WYOMING STORAGE			105,869	102,224	59,004	43,248	172	193
TOTAL STORAGE NORTH CENTRAL REGION			686,879	650,478	342,807	307,699	1,870	1,970
			=======	=======	=======	=======	=======	=======
PACIFIC NORTHWEST REGION								
WASHINGTON								
JACKSON PRAIRIE	WNG	LEWIS	33,900	33,900	18,800	15,100	450	522
TOTAL STORAGE PACIFIC NORTHWEST			33,900	33,900	18,800	15,100	450	522
			======	======	======	======	======	======

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

Table 11: Current Interstate and Intrastate Storage Capacity By State Region

FIELD NAME	COMPANY	COUNTY	CERTIFICATED CAPACITY (MMcf)	MAXIMUM OPERATING CAPACITY (MMcf)	CUSHION GAS VOLUME (MMcf)	WORKING GAS VOLUME (MMcf)	PEAK DAY DEL. RATE (MMcf/d)	DESIGN DAY DEL. RATE (MMcf/d)
PACIFIC								
CALIFORNIA								
** ALISO CANYON	SOCAL	LOS ANGELES	161,525	161,525	91,525	70,000	1,100	1,500
** HONOR RANCHO	SOCAL	LOS ANGELES	37,000	37,000	19,500	17,500	1,000	1,000
** LAGOLETA	SOCAL	SANTA BARBARA	46,096	46,090	32,590	13,500	450	670
** LOS MEDANOS	PG&E	CONTRA COSTA	23,800	22,500	7,500	15,000	200	200
** MCDONALD ISLAND	PG&E	SAN JOAQUIN	140,000	140,000	58,000	82,000	1,400	1,400
** PLAYA DEL REY	SOCAL	LOS ANGELES	7,062	7,062	4,462	2,600	350	350
** PLEASANT CREEK	PG&E	YOLO	7,200	7,200	5,100	2,100	50	50
** WEST MONTBELLO	SOCAL	LOS ANGELES	40,484	39,184	27,484	11,700	550	820
TOTAL CALIFORNIA STORAGE			463,167	460,561	246,161	214,400	5,100	5,990
TOTAL STORAGE PACIFIC			463,167	460,561	246,161	214,400	5,100	5,990
			=======	=======	=======	=======	=======	=======

"*" Means field is under development. "**" Means the field is under state jurisdiction. "x" Indicates where a Design Day figure was not provided.

ATTACHMENT

EXISTING SYSTEM STUDY

INGAA's December 13, 1991 "System Capacity Survey on Behalf of the National Petroleum Council" (with all but one sample page of Parts A and B removed)

December 13, 1991

Memorandum to the Policy Analysis Committee

Subject: 1991 System Capacity Survey on Behalf of the National Petroleum Council

---

The National Petroleum Council (NPC) has asked INGAA to help quantify certain aspects of the interstate pipeline system. INGAA has agreed to cooperate in this survey because it is in the interest of our membership to ensure that the NPC's report reflects our situation accurately.

NPC's Transmission and Storage Task Group has put together a summary of information from a variety of public sources. Their summary covers the design-day capacity of pipelines at regional border crossings, and the capacity and deliverability of storage fields. Some of their information may be out of date. Where this is the case, INGAA would like you to verify, or if necessary to correct, their numbers.

Do not feel overwhelmed by the size of this mailing. While the survey sheets include information on all the companies NPC follows, you need concern yourself only with information about your own pipeline and storage facilities.

The NPC plans to use the results from this survey on a pipeline-by-pipeline basis to fulfill its charge to address the overall deliverability of natural gas. The results of this survey are therefore not being collected on a proprietary basis. INGAA will turn over the responses to the NPC on a disaggregated basis.

You may have someone working in the NPC group who has already begun checking numbers. Pipeline participants in this particular group are:

- Carl Croskey, ANR
- Dick Jones, Williams Natural Gas Co.
- Steve Long, Enron
- Randall Schorre, Tenneco Gas
- Steve Voorhees, Southern Natural Gas Co.
- Mendal Yoho, CNG Transmission

Please return Part A of the completed survey to me by Friday, December 20, 1991, and the longer Part B by Friday, January 3, 1992. Again, note that all you need do is correct, if necessary, the numbers for your pipeline(s) and storage facilities. My fax is (202) 626-3239. Call me at (202) 626-3228 if you have any questions. Thank you for your assistance.

Paul Hoffman
Policy Analyst
Rate and Policy Analysis

Enclosure

GENERAL INSTRUCTIONS

The National Petroleum Council (NPC) has recently summarized design-day capacity and storage capacity and deliverability for a range of pipelines. The NPC culled this information from a variety of publicly available sources. The purpose of this survey is to check the accuracy of information that the NPC has produced, and, if necessary, to correct that information.

In some cases, the numbers that the NPC has reported may be incorrect, or may no longer provide an accurate description of your pipeline. *Please cross out any incorrect number for your pipeline and print the correct number next to it.* Ignore the data for all other pipelines.

The survey consists of two parts:

- Part A contains a pipeline-by-pipeline listing of design-day capacity between geographic regions for various pipelines. You will find your company listed with the borders that the pipeline crosses. Also attached is a map of the geographic regions used by the NPC. Correct the NPC numbers where necessary to reflect your pipeline's capacity figures that have been approved by the FERC and accepted by your company.

- Part B lists pipeline companies with the storage facilities that they own or operate. Correct the figures where necessary for storage capacity and deliverability for each of the facilities you own or operate.

Because these are all publicly available data, we ask you not to use proprietary data in filling out this survey.

If you have any further questions, please call Paul Hoffman at (202)626-3228.

INSTRUCTIONS - PART A

Part A covers design-day capacity between specific geographic regions. A map is attached that defines these geographic regions. For your pipeline, please cross through any incorrect number and print the correct one next to it.

- Column (d), Capacity (MMcf/d) as of 1/1/89, Design Day.
  Please update and correct where appropriate.

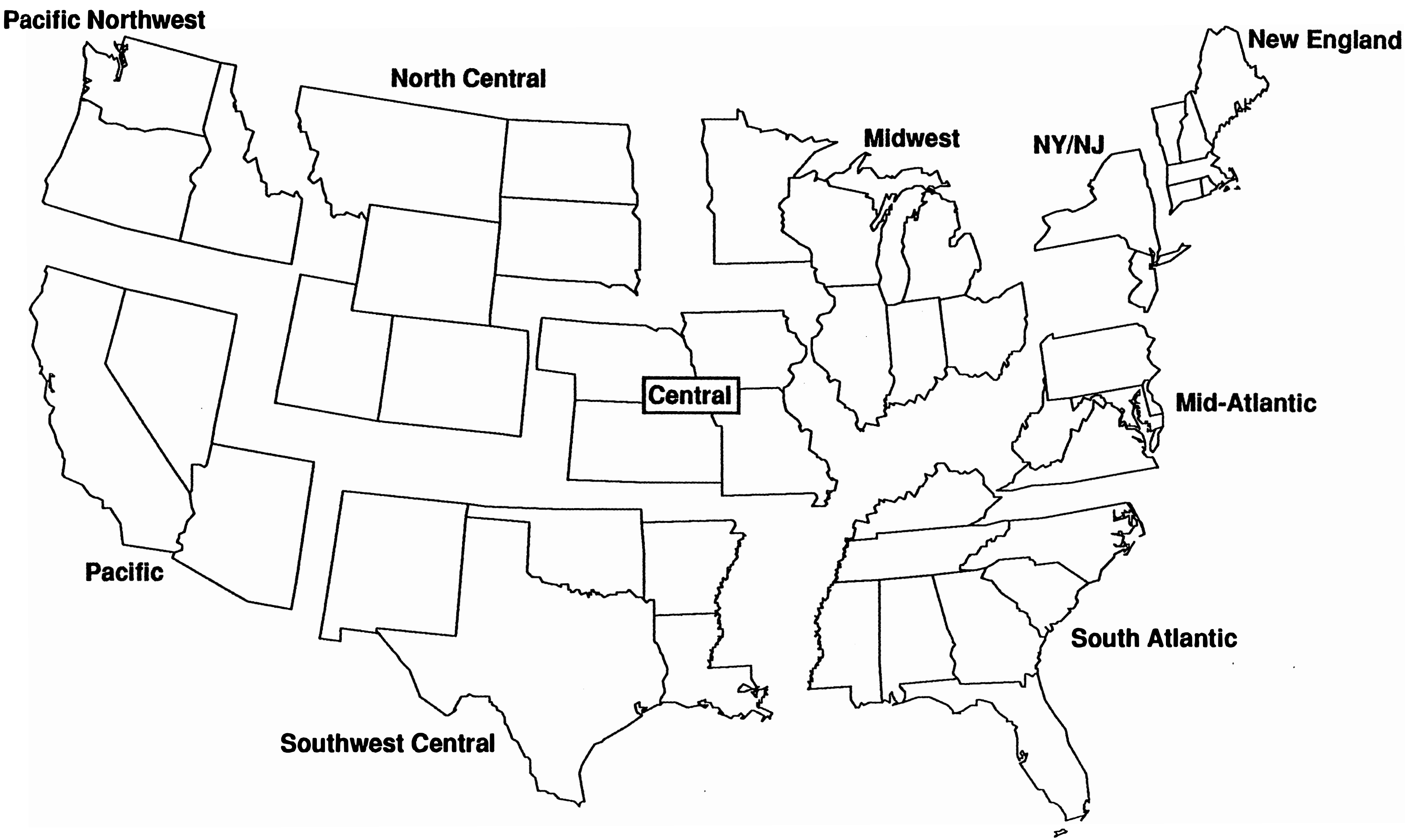
- Columns (e, f, g, h), Approved and Accepted Incremental Capacity (MMcf/d), 1991-1994 Design-Day.
  These are estimates of the incremental capacity already approved by FERC and accepted by your company. Correct as necessary or provide an estimate where "N/A" is listed. (Note that the 1991 figure, column (e), includes the additional capacity approved and accepted between 1/1/89 and 1/1/91.)

- Reverse Flow Lines, all columns (only if applicable to your pipeline).
  Note that the capacity figures that are listed are for the flow of gas in one direction. The direction is specified for each entry. If the reverse direction has been omitted, please add this information in the spaces provided at the end of the questionnaire.

- If your company has more than one line crossing a regional boundary, please provide composite numbers for the lines as a whole.

Ignore all data not pertinent to your system. If you have any further questions, please call Paul Hoffman at (202)626-3228.

Existing Capacity Study Regions



Pipeline Name: ____________________

System Capacity Survey (NPC)

Existing Interstate Pipeline Capacity Study

Pipeline Company (a)	Border Crossing From (b)	Border Crossing To (c)	Approved & Accepted Capacity (MMcf/d) as of 1/1/89 Design Day (d)	Approved & Accepted Incremental Capacity (MMcf/d) 1991 Design Day (e)	1992 Design Day (f)	1993 Design Days (g)	1994 Design Day (h)
Algonquin	NY/NJ	New England	904	124	45	15	0
Altamont	Alberta	No. Central	0	0	0	736	0
ANR	SW Central	Central	622	0	0	0	0
	So. Atlantic	Midwest	1,300	0	0	0	0
	Central	Midwest	521	82	0	0	0
	SW Central	So. Atlantic	1,328	0	0	0	0
Colorado Interstate	No. Central	Central	360	0	0	0	0
	SW Central	Central	160	0	0	0	0
	Central	No. Central	360	0	0	0	0
	SW Central	No. Central	200	0	0	0	0
	No. Central	SW Central	200	0	0	0	0
	Central	SW Central	160	0	0	0	0
Columbia	So. Atlantic	Mid Atlantic	1,198	0	0	0	0
	So. Atlantic	Midwest	763	0	0	0	0
	Mid Atlantic	NY/NJ	189	126	6	0	25

a) Company	b) Field Name	c) County	d) State	e) Certificated Capacity (MMcf)	f) Working Gas Volume (MMcf)	g) Peak-day Delivery Capability (MMcf/d)	h) Design-day Delivery Capability (MMcf/d)
Alcan lng & Recycling	** East Slaughters	Hopkins	Kentucky	767	396	0	
ANRPL	Austin	Mecosta	Michigan	21,323	10,000	700	
ANRPL	Capac*	St. Clair, Lapeer	Michigan	42,220	28,767	340	
ANRPL	Central Charlton 1	Ostego	Michigan	19,000	16,300	300	
ANRPL	Coldwater	Isabella	Michigan	12,988	4,757	100	
ANRPL	Croton	Newaygo	Michigan	5,357	4,200	70	
ANRPL	Goodwell	Newaygo	Michigan	29,625	24,700	300	
ANRPL	Lincoln-Freeman	Clare	Michigan	33,140	23,305	320	
ANRPL	Loreed	Osceola	Michigan	49,300	30,000	640	
ANRPL	Muttonville	Macomb	Michigan	13,387	11,100	400	
ANRPL	North Hamilton	Clare	Michigan	11,141	4,000	50	
ANRPL	Norwich	Newaygo	Michigan	7,913	3,700	50	
ANRPL	Orient	Osceola	Michigan	9,806	5,000	60	
ANRPL	Reed City	Osceola	Michigan	28,591	18,000	300	
ANRPL	South Chester 15	Ostego	Michigan	19,448	16,815	270	
ANRPL	Winfield	Montcalm	Michigan	18,680	5,351	60	
ANRSC	Cold Springs 12	Kalaska	Michigan	27,939	24,216	280	
ANRSC	Cold Springs 31	Kalaska	Michigan	5,734	4,987	62	
ANRSC	Eccelsior 6-East Kalaska	Kalaska	Michigan	11,089	9,589	120	
ANRSC	Rapid River 35	Kalaska	Michigan	17,420	15,144	250	
Arkansas Louisiana Gas Co.	** Collinson	Cowley	Kansas	2,393	1,000	0	
Arkansas Louisiana Gas Co.	** Ulan (As)	Pittsburg	Oklahoma	7,740	766	15	
Arkansas Oklahoma Gas Corp.	** Lavaca Deep(A)	Sebastian	Arkansas	3,353	63	12	
Arkansas Western Gas Co.	** Jethro	Franklin	Arkansas	38,000	12,323	100	
Arkansas Western Gas Co.	** Lone Elm	Franklin	Arkansas	0	0	0	
Arkansas Western Gas Co.	** Watalula	Franklin	Arkansas	0	0	0	
Arkansas Western Gas Co.	** White Oak	Franklin	Arkansas	0	0	0	

* Field under development ** Non-jurisdictional

APPENDIX D

METHODOLOGY FOR ANALYZING PEAK-DAY PIPELINE CAPACITY REQUIREMENTS

OVERVIEW

The National Petroleum Council analyzed the domestic capacity requirements of the transmission and storage sectors to support projected levels of demand through the year 2010. In support of the overall natural gas study, the Council prepared two reference cases, the High Reference Case (Reference Case 1, the moderate energy growth scenario) with a 2010 consumption level of 24 trillion cubic feet (TCF) and the Low Reference Case (Reference Case 2, the low energy growth scenario) with a 2010 consumption level of 21 TCF. The Transmission and Storage Task Group used these two cases as the basis of its analysis of the need for future capacity.

The task group approached the study of capacity expansions by looking at the average-January-day and peak-day requirements implicit in the annual projections provided in these two cases. The reasons for addressing the capacity requirements at this level were twofold. First, the transmission and storage system is developed to meet the firm peak-day requirements of its customers. Second, this approach allowed the evaluation of the seasonal aspects of the demand and the role of storage in meeting the seasonal demand variation. The role of storage in meeting demand is not normally considered in annual projections of market equilibrium.

The general analytical approach involved:

- Projecting average-January-day and peak-day supply and demand levels by Demand Region
- Calculating interregional gas transfers and capacity expansions necessary to balance supply with demand.

To understand the sequencing of transmission and storage capacity additions over time, the projections of supply and demand were analyzed at five-year increments.

This peak-day analysis was accomplished using a network model of the national grid that performed a supply/demand balance for each region and attempted to meet demand with an overall, national supply sequencing strategy. The network model used in the study is based on the model used for the 1989 NPC study of natural gas pipeline capacity.[1] The model has been enhanced to evaluate the 10 federal regions, multiple periods, and to address facility expansions over the projection period through 2010.

This appendix will first describe the model structure and the approach used to evaluate the capacity additions. Then it will describe the data used in the analysis, specifically the approach used to generate peak-day supply and demand projections from the annual projections.

Some limitations of the model and this analytical approach should be noted.

---

[1] National Petroleum Council, *Petroleum Storage & Transportation*, Volume III: Natural Gas Transportation, April 1989.

- The capacity additions derived from this analysis are not based on any actual cost factors.
- The capacity additions are specific to the supply and demand projections of the two cases presented. Other cases with differing assumptions may result in different projections of capacity additions.
- Because of the focus on 10 federal regions, some areas may need additional capacity within a region. This will not be evident from the results of this analysis.

NETWORK MODEL

The National Petroleum Council Network Model was developed to determine the feasibility of meeting peak period demands given a forecast of supply capability and capacity of major transmission corridors. The Network Model is a nonlinear model that solves a network optimization problem defined by regional supply and demand centers connected by interregion pipeline arcs.

Model Specification

The pipeline system is represented as a series of links connected to the appropriate regions. The Network Model performs a supply/demand balance for each region and attempts to meet demand with an overall, national, least-cost supply sequencing strategy.

Internally, the model is based on a network structure of supply, demand, and pipeline nodes. Supply and demand nodes are connected to the regions by a series of links. An illustration of the network used by the model, supply sources, and demand sectors can be found in Figure D-1.

A cost function was assigned to each link and used to calculate a model "cost" as a function of link flow. The cost functions assigned to the supply, demand, and pipeline links are described below:

- Supply links were assigned a linear cost function, each with a coefficient that forced supply to be taken in the desired order. The supply sources in the order of priority are:
  - Domestic production
  - Pipeline imports
  - LNG imports
  - Storage
  - Peak shaving.
- Demand links were assigned a cost function that generated an increasing cost for fractional levels of demand service. This function forced demand to be served in a sequential manner with all of the higher priority sector served before any of the next priority class received service. The sector demand was prioritized as follows:
  - Residential, pipeline fuel, lease and plant fuel, unaccounted-for gas, exports
  - Commercial
  - Industrial (firm service and cogeneration)
  - Electric utility (firm service and combined cycle)
  - Industrial interruptible service
  - Electric utility interruptible service.
- Pipeline links were also assigned a cost function that attempted to equalize fractional use of pipeline capacity in situations where multiple feasible combinations of pipeline utilization gave equal supply costs.

The model analyzes the ability of the system to supply demand based on an initial specification of supply sources, pipeline capacity, and demand requirements. The first year analyzed is 1991. For the subsequent forecast years, the information regarding supply sources, pipeline capacity, and demand requirements are updated to reflect the forecast values and other assumptions specific to that forecast year, and the model is run again to evaluate the system capabilities under these changed circumstances.

The model solves the set of flows that minimizes the penalty for curtailing demand. If demand is curtailed, the model adjusts the flows so that levels of curtailment by sector are equalized across regions, subject to available pipeline capacity.[2]

[2] The model uses a nonlinear optimization package, RSDNET, developed by the University of Florida, Department of Industrial and Systems Engineering.

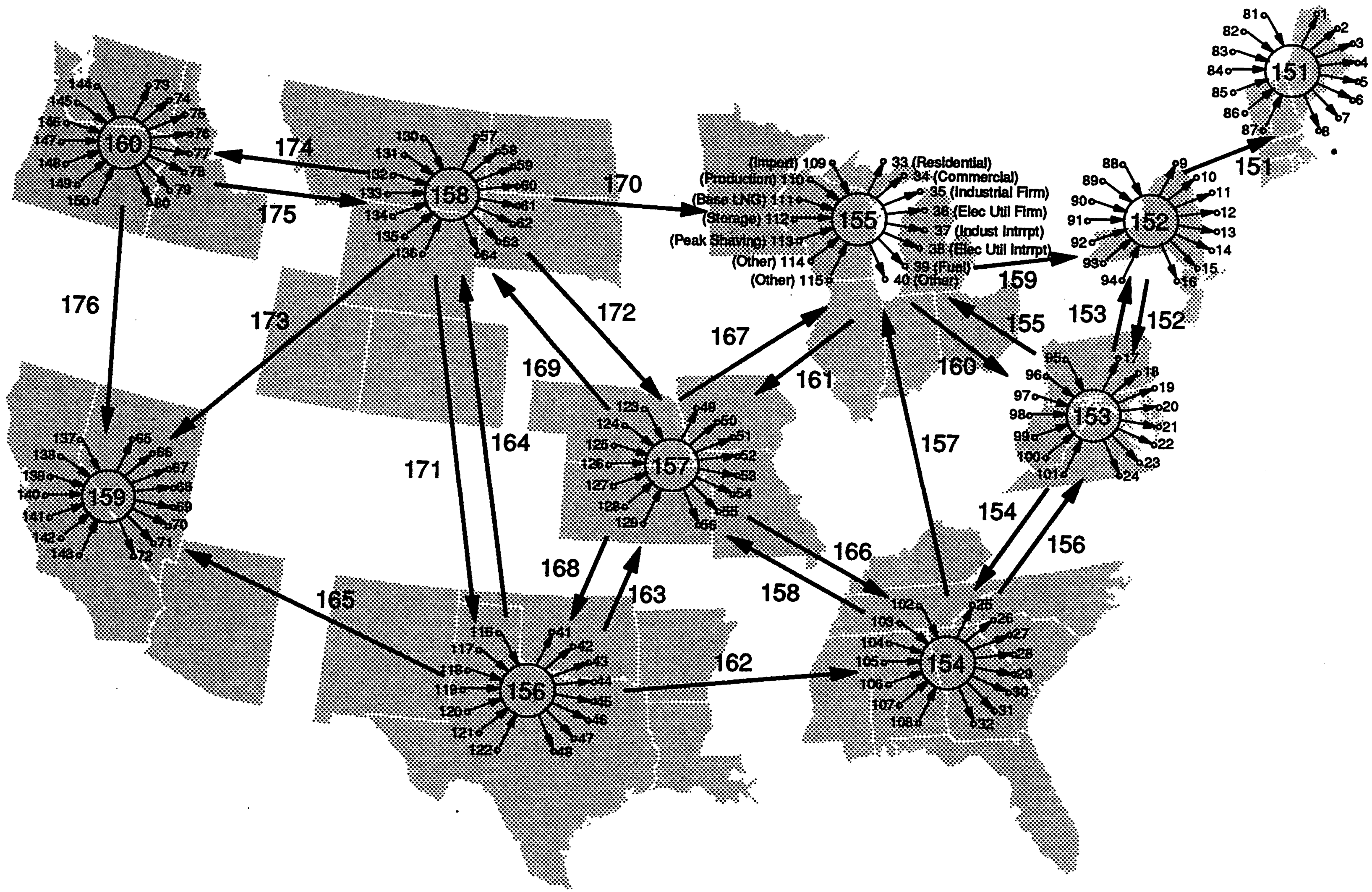


Figure D-1. Network Structure of NPC Model.

Capacity Expansions

When model results indicate demand curtailments, off-line analysis was undertaken to evaluate the capacity expansion requirements. For each region where curtailments were seen, the additional quantities of supply needed were identified. Capacity expansions to meet the curtailed demand was allocated to three types of facilities: pipeline transmission, imports, and storage.

The allocation of additional capacity to these three facility types was regionally specific. When capacity was added to meet demand requirements on an average January day in a given year, that capacity was available on the peak day in that year. Also, when capacity was added in any year, that capacity was included in the base capacity available for the analysis of later years.

Model Flexibility

While the model was used in this report for the analysis of peak-day requirements, it may be used for analysis of the average-day or monthly requirements. Scenario variations, such as colder than normal weather, are easily implemented. Variations may also include alternative priority schemes for demand and supply capacity and routing.

Model Output

- Regional, sectoral consumption, and curtailments (if any).
- Utilization of regional supply sources and excess supplies (if any).
- Interregional utilization of aggregate transmission corridors.

Appendix F provides the model output for the two cases analyzed in this study. In this appendix and in the output tables shown in Appendix F, Reference Cases 1 and 2 are referred to as High and Low Reference Cases, respectively.

DATA DOCUMENTATION

Demand

The demand projections used in the analysis were derived from the annual projections by sector and by region from the NPC Reference Cases. Tables D-1H and D-1L provide the average-January-day and peak-day demand levels used in the analysis for the High and Low Reference Cases, respectively.

The annual forecasts were converted to represent both average-January-day and peak-day gas demands by applying factors that represent the seasonal profile of gas use in each sector. The firm versus interruptible nature of current demand in the industrial and electric utility sectors was also characterized. The factors are based on an extensive analysis of seasonal gas demand profiles by region, conducted by the Gas Research Institute and made available for use in this study.[3] The factors are provided in Tables D-2 and D-3 for the average-January-day factors and peak-day factors, respectively. The same factors were used for the High and Low Reference Cases.

Residential and Commercial Demand

The seasonal profile of residential and commercial consumption was based on historical patterns. A two-step process was used to derive the profile. First, the historical consumption data were adjusted, based on the results of a regression analysis, to represent "normal" weather patterns. Second, seasonal patterns for each region and sector were derived based on the normalized consumption levels.

Regression analysis was used to examine the relationship between the weather in each federal region over the period from 1985 through 1990 and the consumption of natural gas during this period. Monthly deliveries per customer in each region were regressed on lagged and unlagged monthly average degree day data (weighted by gas consumption in each state of the region) for the years 1985 through 1990. The reason for using the lagged degree day data in the regressions was to adjust reported monthly deliveries to more accurately represent actual deliveries. This adjustment was necessary because of the various billing cycles used by gas companies for their smaller customers. Deliveries were divided by customers to account for growth in the market.

---

[3] Work sponsored by the Gas Research Institute, which is described in GRI Report No. 92/0475, *The Seasonal Demand and Supply of Natural Gas in the Lower-48 United States.*

The regression analysis was used to create estimates of typical monthly natural gas consumption assuming normal weather conditions in the residential and commercial sectors within each region. The proportion of normalized January consumption to total annual consumption for an average over the period from 1985 through 1990 was calculated for each region. These factors (Table D-2) were applied to the annual regional forecast to derive the average-January-day demand for the years 1991, 1995, 2000, 2005, and 2010. The peak-day demand was then calculated by multiplying the average-January-day demand by the peak-day factors (Table D-3). The peak-day factors for the residential sector vary over the forecast, while they are constant for the commercial sector. All factors are the same for the High and Low Reference Cases.

All demand in the residential and commercial sectors is assumed to be firm demand, i.e., it must be served and cannot be interrupted.

Industrial Demand

The industrial sector monthly consumption patterns share some of the characteristics of the residential and commercial sectors in that there is increased use during the winter. Thus, monthly lows tend to be in the non-heating months, but occasionally fall in the winter months because of fuel-switching and other factors. As a result, the regression analysis used for the residential and commercial sectors did not provide a statistically acceptable fit for the industrial sectors.

As an alternative, data for the five years 1985 through 1990 (excluding 1986)[4] were used to develop an average monthly distribution pattern.

The projections of annual demand for the industrial sector is provided in three categories: firm service, interruptible service, and cogeneration. Average-January-day (Table D-2) and peak-day (Table D-3) factors are provided for each type of service by region. The peak-day factors for cogeneration are 1 in every region so that cogeneration demand on the peak day equals cogeneration demand on the average January day. Peak-day factors for interruptible service are zero in every region so that no industrial interruptible demand will be met on the peak day. Cogeneration demand is classified as firm service and the model structure considers only the total industrial firm demand, i.e., the sum of the separate firm demand and cogeneration demand.

None of the industrial sector average-January-day or peak-day factors vary over the forecast. The same factors are used for the High and Low Reference Cases.

Electric Utility Demand

Monthly electric utility sector consumption patterns show the impacts of a wide variety of factors. These include fuel switching due to fluctuating price differentials between natural gas and residual fuel oil (or other fuels), weather conditions, air pollution considerations, pipeline capacity, storage operations, and the role of gas in regional power generation. Like the industrial sector, the regression analysis approach did not provide a statistically acceptable fit for the electric utility sectors.

As an alternative, data for the five years 1985 through 1990 (excluding 1986)[5] were used to develop an average monthly distribution pattern.

The projections of electric utility sector annual demand is provided in three categories: firm service, interruptible service, and combined cycle. Average-January-day (Table D-2) and peak-day (Table D-3) factors are provided for each type of service by region. The average-January-day factors for combined-cycle demand vary over the forecast, all other average-January-day and peak-day factors for the electric utility sector remain constant. The peak-day factors for both combined-cycle and interruptible demand are zero in every region so these types of demand will not be met on the peak day. Combined-cycle demand is classified as firm service and the model structure considers only the total electric utility firm demand, i.e., the sum of the separate firm demand and combined-cycle demand.

The same factors are used for the High and Low Reference Cases.

---

4 Data for 1986 were excluded because of the high level of fuel switching that occurred that year as a result of the collapse of oil prices.

5 See Note 4.

Lease and Plant Fuel

Annual demand for lease and plant fuel is provided only at the national level in the High and Low Reference Cases. The national quantity is shared among the Demand regions based on regional gas production. The annual demand in each region is converted to an average-January-day demand (Table D-1) using "Monthly Production Distribution" factors for each region provided by Jensen Associates, Inc.[6] These factors do not vary over the forecast. Regional peak-day factors, derived from those used in the 1989 NPC study on natural gas, are applied to the average-January-day demand to derive peak-day demand (Table D-1). The peak-day factors vary over the forecast. The same average-January-day and peak-day factors are used in the High and Low Reference Cases.

Pipeline Fuel

Annual demand for pipeline fuel, which is also provided only at the national level, is treated similarly to lease and plant fuel. The differences are that the regional distribution of the national demand is based on the regional share of gas deliveries to the four major consuming sectors rather than on regional production, and that "Monthly Pipeline Fuel Distribution" factors from Jensen Associates, Inc.[7] are used to generate average-January-day demand.

Unaccounted-For Natural Gas

Annual demand for unaccounted-for natural gas is provided only at the national level and includes net exports. Because the model requires total exports, net exports were removed from the Energy and Environmental Analysis, Inc. projection of unaccounted-for/export demand.[8]

After adjusting for net exports, the annual demand for unaccounted-for natural gas is still only at a national level. This annual, national demand is thus treated in the same way as lease and plant fuel. The only difference being that "Monthly Unaccounted For Gas Distribution" factors from Jensen Associates, Inc.[9] are used to generate average-January-day demand.

Exports

Separate daily export volumes by exit point, consistent with the High and Low Reference Case projections, are provided by Energy and Environmental Analysis, Inc.[10] These data are assigned to Demand Regions, but exports to Naco, Mexico are not used because it is assumed that there are no exports from the South Pacific region to Mexico.

Note on Model Structure

The model considers the sum of lease and plant fuel, pipeline fuel, unaccounted-for gas, and exports as a single demand sector called "fuel." This sector is classified as receiving firm service.

Supply

Regional annual production is from the High and Low Reference Case projections. For imports, storage, pipeline capacity, and peak shaving data, other sources as noted below were used. The same data were used for average-January-day and peak-day analysis for all sources of supply except for storage as noted below.

Production

Tables D-4H and D-4L provide, by Demand region, the average-day, average-January-day, and peak-day daily capacities implicit in the High and Low Reference Cases, respectively. These data are the actual productive capacity levels used in the model.

[6] Jensen Associates, Inc., memo of September 25, 1991, from Edwin F. Hardy.

[7] Ibid.

[8] Imports and exports by entry and exit point, consistent with the High and Low Reference Case projections, are provided by Energy and Environmental Analysis, Inc. (EEA) in a memo of August 31, 1992, from Robert Crawford. Net exports were derived from this memo as the sum of (1) imports at Emerson "TCPL Service," (2) exports at St. Clair, and (3) "Import Flows (net)" provided for Mexico. The data were converted from million cubic feet per day to quadrillion BTU per year and subtracted from the EEA annual, national demand for unaccounted for/exports.

[9] Jensen Associates, Inc., memo of September 25, 1991, from Edwin F. Hardy.

[10] Energy and Environmental Analysis, Inc., memo from Robert Crawford of August 31, 1992.

Estimates of daily Demand region production capacity are derived in the following manner:

- The annual forecasts provide production and capacity utilization estimates in a different regional format (called hydrocarbon regions). For the average day, the projections are allocated to Demand regions, divided by the capacity utilization estimates, and divided by the number of days in the year (Tables D-5H and D-5L).
- The amount of productive capability available on an average January day was derived by reducing the average-day production by 2.5 percent for all regions to account for weather related difficulties. For the peak-day analysis, average-day production was reduced by 2.5 percent in all regions except the Southwest Central, which was reduced by 6.5 percent, and the Central, which was reduced by 4 percent.

Pipeline Imports

Pipeline import capacity used in the analysis is based on two sources: proposed capacity as of 1992 (from Appendix C, Existing System Study) and import flows from the High and Low Reference Cases adjusted to 100 percent utilization.[11]

The data used in the analysis are shown in Tables D-6H and D-6L for the High and Low Reference Cases, respectively. Within each case, the same import capacities were used for the average January day and peak day.

For 1991 and 1992, the model uses the proposed capacities from the Existing System Study. For 1993 through 2010, the maximum of the 1992 proposed capacity and the flow at 100 percent utilization is used in each region. To prevent a decline in import capacity in the model, the previous year's value is used if the flow rate in any year is less than the value used in the previous year.

LNG Imports

Base load LNG, or LNG import capacity, is provided specifically for the average January day and the peak day by LNG facility and are then assigned to Demand regions.[12] It is assumed that capacity at Cove Point, Maryland, in the Middle Atlantic region, is not available over the forecast. The capacities used in the analysis are shown in Table D-7.

Underground Storage

Average-January-day underground storage deliverability is taken from daily withdrawal rates by month developed by Jensen Associates, Inc.[13] The highest withdrawal rate that occurred in any month from January 1985 through December 1990 in each region is used for the average January day.

Peak-day deliverability rates for each region are taken from Table 7 of Appendix C, Existing System Study.

The same deliverability rates are used in the High and Low Reference Cases. These rates are shown in Table D-8.

Peak Shaving

Data for propane air and LNG used for peak shaving is provided, by state, by the Gas Research Institute.[14] These data are summed and aggregated into Demand regions, and made available to the model as potential capacity. To simulate observed peak-shaving operations, peak shaving is limited in the model to regional levels derived from the American Gas Association. Both the capacity and the operational levels assumed for the analysis are shown in Table D-9. Peak shaving is only available on the peak day and the same values are used in the High and Low Reference Cases.

Pipeline Capacity

Interregional pipeline capacity is derived from the proposed capacities provided by

[11] Energy and Environmental Analysis, Inc., memo of August 31, 1992, from Robert Crawford. The import flows are provided by entry point at a 90% utilization rate. The flows are increased to 100% utilization by dividing by 0.9, and are then aggregated into Demand regions.

[12] Memo of February 24, 1992, from Deborah Plattsmier, "Current Sustainable & Peak LNG Import Capacity and Planned Additions Through 2010."

[13] Jensen Associates, Inc., *1985-1990 Monthly Data Series on Gas Consumption, Storage, & Production by Federal Regions*, September 1991.

[14] Gas Research Institute, *The Seasonal Demand and Supply of Natural Gas in the Lower-48 United States*, GRI Report No. 92/0475, prepared under GRI Contract, October 1992. Appendix D, "Propane-Air Peakshaving Facilities in the United States," and Appendix E, "LNG Peakshaving Facilities in the United States."

Demand region and pipeline company in Table 8 of Appendix C, Existing System Study. The capacities used for 1991, the 1992 capacity additions, and the resulting 1992 capacities are shown in Table D-10. These capacities are used for both the High and Low Reference Cases.

Two adjustments are made to the Appendix C data for 1992 capacity additions. The Iroquois project imports gas from Canada into New York. The project then takes some of this gas into Connecticut and back into New York at Long Island. For the Iroquois project, Appendix C shows 548 million cubic feet per day (MMCF/D) of capacity from the New York/New Jersey region to New England, and 205 MMCF/D from New England to New York/New Jersey. This path is simplified in the model by using the net value of 343 MMCF/D from New York/New Jersey to New England. The model has no pipeline link from New England to the New York/New Jersey region.

The other adjustment affects the Cornerstone project from the Southwest Central region to the South Atlantic. The projected capacity of 600 MMCF/D provided in Appendix C is not used due to postponement of the project.

Table D–1H.

Average January Day and Peak Day Demand by Region
High Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
New England										
Residential	913	1,096	1,181	1,290	1,403	1,726	1,808	1,807	1,805	1,824
Commercial	483	485	520	597	635	893	897	963	1,105	1,175
Industrial										
Firm	119	111	101	137	154	161	151	137	186	210
Cogeneration	0	72	116	169	216	0	72	116	169	216
Interruptible	57	55	47	66	73	0	0	0	0	0
Electric Utility										
Firm	0	0	0	0	0	0	0	0	0	0
Combined Cycle	0	173	193	251	336	0	0	0	0	0
Interruptible	2	2	3	3	4	0	0	0	0	0
Pipeline Fuel	69	84	92	106	118	112	136	149	171	191
Lease and Plant Fuel	0	0	0	0	0	0	0	0	0	0
Unaccounted For	0	0	0	0	0	0	0	0	0	0
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**1,642**	**2,078**	**2,253**	**2,618**	**2,940**	**2,891**	**3,065**	**3,171**	**3,436**	**3,616**
NY/NJ										
Residential	2,888	3,165	3,162	3,214	3,279	4,794	5,507	5,534	5,625	5,705
Commercial	1,595	1,613	1,599	1,782	1,905	2,552	2,581	2,559	2,852	3,048
Industrial										
Firm	216	224	189	233	242	308	321	270	333	346
Cogeneration	9	181	266	300	319	9	181	266	300	319
Interruptible	258	268	229	280	291	0	0	0	0	0
Electric Utility										
Firm	3	3	3	3	5	3	3	3	3	5
Combined Cycle	0	83	119	207	343	0	0	0	0	0
Interruptible	98	106	91	124	137	0	0	0	0	0
Pipeline Fuel	206	222	225	241	255	339	364	367	396	418
Lease and Plant Fuel	4	4	4	5	5	6	6	7	8	9
Unaccounted For	1	1	1	1	1	2	1	1	1	1
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**5,277**	**5,870**	**5,888**	**6,390**	**6,782**	**8,012**	**8,964**	**9,007**	**9,518**	**9,850**

Table D–1H. (Continued)

Average January Day and Peak Day Demand by Region
High Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
Middle Atlantic										
Residential	2,414	2,596	2,533	2,506	2,479	4,345	5,141	5,192	5,263	5,331
Commercial	1,299	1,307	1,322	1,479	1,564	2,274	2,287	2,313	2,589	2,737
Industrial										
Firm	411	377	325	392	406	670	615	529	638	662
Cogeneration	28	291	425	481	516	28	291	425	481	516
Interruptible	897	820	708	853	882	0	0	0	0	0
Electric Utility										
Firm	5	5	11	8	11	5	5	11	8	11
Combined Cycle	0	78	356	732	1,064	0	0	0	0	0
Interruptible	11	15	21	20	22	0	0	0	0	0
Pipeline Fuel	251	263	276	310	331	493	509	527	595	632
Lease and Plant Fuel	72	73	82	92	103	142	141	156	176	198
Unaccounted For	17	13	14	14	13	33	26	28	26	25
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**5,406**	**5,838**	**6,073**	**6,888**	**7,391**	**7,990**	**9,015**	**9,181**	**9,776**	**10,111**
South Atlantic										
Residential	2,148	2,256	2,178	2,106	2,024	4,489	5,234	5,358	5,434	5,466
Commercial	1,331	1,418	1,562	1,752	1,855	2,636	2,808	3,093	3,469	3,673
Industrial										
Firm	819	874	841	1,003	1,074	1,269	1,355	1,304	1,555	1,664
Cogeneration	28	97	144	172	194	28	97	144	172	194
Interruptible	1,388	1,483	1,427	1,704	1,819	0	0	0	0	0
Electric Utility										
Firm	221	184	186	192	213	221	184	186	192	213
Combined Cycle	0	93	926	1,746	2,756	0	0	0	0	0
Interruptible	202	170	172	175	197	0	0	0	0	0
Pipeline Fuel	252	261	298	351	400	386	397	447	527	596
Lease and Plant Fuel	77	176	222	227	230	118	268	333	340	342
Unaccounted For	18	33	40	34	30	28	50	60	51	44
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**6,484**	**7,045**	**7,996**	**9,463**	**10,790**	**9,174**	**10,393**	**10,925**	**11,740**	**12,193**

Table D–1H. (Continued)
Average January Day and Peak Day Demand by Region
High Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
Midwest										
Residential	9,145	9,451	9,389	9,390	9,450	16,827	18,807	19,060	19,436	20,035
Commercial	4,662	4,716	4,833	5,287	5,552	8,391	8,489	8,699	9,516	9,994
Industrial										
Firm	1,053	1,106	1,034	1,077	1,106	1,664	1,747	1,634	1,702	1,747
Cogeneration	3	81	122	128	131	3	81	122	128	131
Interruptible	2,614	2,748	2,579	2,681	2,751	0	0	0	0	0
Electric Utility										
Firm	8	13	21	21	24	8	13	21	21	24
Combined Cycle	0	265	285	782	1,342	0	0	0	0	0
Interruptible	81	152	231	233	258	0	0	0	0	0
Pipeline Fuel	860	2,392	2,438	2,513	2,633	1,463	4,057	4,126	4,249	4,447
Lease and Plant Fuel	58	65	79	82	92	99	111	134	138	155
Unaccounted For	15	13	15	13	13	25	22	26	22	22
Exports	1,012	1,516	1,555	1,587	1,665	1,012	1,516	1,555	1,587	1,665
Total Demand	**18,499**	**21,003**	**21,026**	**22,207**	**23,353**	**28,481**	**33,329**	**33,822**	**35,214**	**36,555**
Southwest Central										
Residential	2,657	2,623	2,539	2,489	2,447	6,218	6,531	6,703	6,820	6,948
Commercial	1,380	1,459	1,476	1,674	1,822	2,677	2,830	2,863	3,248	3,534
Industrial										
Firm	6,578	7,173	7,163	7,431	7,688	7,894	8,608	8,595	8,917	9,225
Cogeneration	72	63	147	206	219	72	63	147	206	219
Interruptible	1,486	1,619	1,617	1,680	1,738	0	0	0	0	0
Electric Utility										
Firm	2,139	2,141	2,464	2,412	2,407	2,139	2,141	2,464	2,412	2,407
Combined Cycle	0	0	230	1,015	1,968	0	0	0	0	0
Interruptible	516	517	594	583	582	0	0	0	0	0
Pipeline Fuel	446	1,137	1,380	1,001	545	546	1,392	1,690	1,225	666
Lease and Plant Fuel	2,506	2,326	2,182	2,309	2,175	3,069	2,849	2,672	2,826	2,662
Unaccounted For	581	428	385	338	276	711	524	471	414	338
Exports	44	684	904	493	0	44	684	904	493	0
Total Demand	**18,361**	**19,486**	**20,176**	**21,139**	**21,865**	**23,325**	**24,938**	**25,605**	**26,069**	**25,999**

Table D–1H. (Continued)
Average January Day and Peak Day Demand by Region
High Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
Central										
Residential	2,054	2,033	2,022	2,012	2,013	3,718	3,965	4,004	4,044	4,146
Commercial	1,101	1,087	1,101	1,203	1,265	1,816	1,793	1,816	1,984	2,088
Industrial										
Firm	250	281	281	293	301	364	411	411	428	440
Cogeneration	0	6	9	9	13	0	6	9	9	13
Interruptible	592	663	663	697	713	0	0	0	0	0
Electric Utility										
Firm	5	8	8	8	8	5	8	8	8	8
Combined Cycle	0	14	143	240	377	0	0	0	0	0
Interruptible	27	34	44	43	45	0	0	0	0	0
Pipeline Fuel	204	202	211	220	230	322	321	335	350	365
Lease and Plant Fuel	129	130	112	99	80	204	207	178	158	127
Unaccounted For	26	21	17	13	9	41	33	27	20	14
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**4,387**	**4,480**	**4,612**	**4,838**	**5,053**	**8,471**	**4,885**	**5,264**	**5,687**	**8,157**
North Central										
Residential	1,058	1,074	1,097	1,141	1,191	2,117	2,202	2,259	2,305	2,370
Commercial	683	685	690	766	826	1,352	1,357	1,367	1,516	1,636
Industrial										
Firm	99	122	133	146	150	131	163	176	194	199
Cogeneration	0	38	66	72	75	0	38	66	72	75
Interruptible	287	351	383	423	437	0	0	0	0	0
Electric Utility										
Firm	3	16	16	16	16	3	16	16	16	16
Combined Cycle	0	0	557	849	1,079	0	0	0	0	0
Interruptible	56	242	242	254	279	0	0	0	0	0
Pipeline Fuel	109	121	154	176	193	183	211	264	300	328
Lease and Plant Fuel	311	438	556	659	804	524	762	952	1,123	1,364
Unaccounted For	70	79	96	94	100	119	137	164	161	169
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**2,674**	**3,167**	**3,989**	**4,597**	**5,150**	**4,429**	**4,885**	**5,264**	**5,687**	**6,157**

Table D–1H. (Continued)
Average January Day and Peak Day Demand by Region
High Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
Pacific										
Residential	2,572	2,611	2,640	2,684	2,728	5,634	6,056	6,178	6,254	6,384
Commercial	1,177	1,114	1,179	1,355	1,444	1,919	1,816	1,921	2,209	2,354
Industrial										
Firm	753	766	868	841	862	903	920	1,041	1,009	1,035
Cogeneration	169	544	531	744	822	169	544	531	744	822
Interruptible	697	710	802	779	799	0	0	0	0	0
Electric Utility										
Firm	73	80	100	118	124	73	80	100	118	124
Combined Cycle	0	0	71	234	513	0	0	0	0	0
Interruptible	837	940	1,155	1,353	1,440	0	0	0	0	0
Pipeline Fuel	226	235	258	282	302	403	419	465	507	541
Lease and Plant Fuel	61	69	101	153	191	109	123	183	275	342
Unaccounted For	17	15	21	27	29	30	27	38	48	51
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**6,582**	**7,084**	**7,726**	**8,570**	**9,255**	**9,238**	**9,985**	**10,458**	**11,164**	**11,653**
Northwest										
Residential	417	416	408	399	389	1,076	1,240	1,314	1,369	1,421
Commercial	335	342	325	358	386	822	838	796	876	946
Industrial										
Firm	61	64	64	71	74	94	99	99	110	115
Cogeneration	0	34	63	94	119	0	34	63	94	119
Interruptible	339	347	347	386	406	0	0	0	0	0
Electric Utility										
Firm	0	0	0	0	0	0	0	0	0	0
Combined Cycle	0	0	0	113	211	0	0	0	0	0
Interruptible	0	0	0	0	0	0	0	0	0	0
Pipeline Fuel	47	47	48	55	61	73	73	74	85	94
Lease and Plant Fuel	0	0	1	1	1	1	1	1	2	2
Unaccounted For	0	0	0	0	0	0	0	0	0	0
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**1,200**	**1,251**	**1,254**	**1,478**	**1,648**	**2,066**	**2,286**	**2,346**	**2,536**	**2,697**

Table D-1L.

Average January Day and Peak Day Demand by Region
Low Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
New England										
Residential	913	1,097	1,165	1,257	1,350	1,726	1,843	1,841	1,835	1,836
Commercial	483	482	504	570	590	894	891	933	1,054	1,091
Industrial										
Firm	119	101	65	93	83	161	137	88	127	112
Cogeneration	0	72	113	163	209	0	72	113	163	209
Interruptible	57	47	32	45	40	0	0	0	0	0
Electric Utility										
Firm	0	0	0	0	0	0	0	0	0	0
Combined Cycle	0	173	185	213	255	0	0	0	0	0
Interruptible	2	2	1	3	3	0	0	0	0	0
Pipeline Fuel	69	83	86	98	104	112	134	138	158	167
Lease and Plant Fuel	0	0	0	0	0	0	0	0	0	0
Unaccounted For	0	0	0	0	0	0	0	0	0	0
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**1,643**	**2,057**	**2,151**	**2,440**	**2,634**	**2,892**	**3,077**	**3,113**	**3,336**	**3,416**
NY/NJ										
Residential	2,888	3,188	3,136	3,142	3,157	4,795	5,420	5,425	5,405	5,430
Commercial	1,595	1,614	1,576	1,727	1,811	2,552	2,583	2,521	2,763	2,897
Industrial										
Firm	216	198	141	163	154	308	283	201	233	220
Cogeneration	9	181	263	284	309	9	181	263	284	309
Interruptible	262	241	169	198	186	0	0	0	0	0
Electric Utility										
Firm	3	3	3	3	3	3	3	3	3	3
Combined Cycle	0	79	100	147	215	0	0	0	0	0
Interruptible	98	106	63	120	118	0	0	0	0	0
Pipeline Fuel	206	220	211	225	227	339	361	344	367	370
Lease and Plant Fuel	4	4	4	4	4	6	6	6	7	7
Unaccounted For	1	1	1	1	1	2	1	1	2	1
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**5,282**	**5,835**	**5,666**	**6,015**	**6,186**	**8,014**	**8,838**	**8,764**	**9,064**	**9,239**

Table D–1L. (Continued)

Average January Day and Peak Day Demand by Region
Low Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
Middle Atlantic										
Residential	2,415	2,622	2,503	2437	2,374	4,346	5,008	5,007	5,020	5,009
Commercial	1,300	1,298	1,273	1,383	1,402	2,275	2,271	2,228	2,419	2,453
Industrial										
Firm	411	330	229	263	229	670	537	374	428	374
Cogeneration	28	291	416	456	497	28	291	416	456	497
Interruptible	899	725	500	573	505	0	0	0	0	0
Electric Utility										
Firm	5	5	8	8	11	5	5	8	8	11
Combined Cycle	0	80	89	451	875	0	0	0	0	0
Interruptible	11	14	20	20	20	0	0	0	0	0
Pipeline Fuel	251	257	238	265	275	493	493	450	500	515
Lease and Plant Fuel	72	72	76	87	88	142	138	144	165	165
Unaccounted For	17	14	16	17	16	33	27	30	33	29
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**5,409**	**5,708**	**5,370**	**5,959**	**6,292**	**7,992**	**8,771**	**8,655**	**9,030**	**9,054**
South Atlantic										
Residential	2,148	2,313	2,181	2,067	1,942	4,490	4,974	4,973	4,961	4,973
Commercial	1,331	1,392	1,471	1,590	1,561	2,636	2,756	2,912	3,148	3,090
Industrial										
Firm	819	786	609	668	594	1,269	1,218	944	1,035	921
Cogeneration	28	97	141	163	184	28	97	141	163	184
Interruptible	1,390	1,329	1,035	1,134	1,009	0	0	0	0	0
Electric Utility										
Firm	221	162	165	170	194	221	162	165	170	194
Combined Cycle	0	0	439	1,243	2,107	0	0	0	0	0
Interruptible	202	148	152	156	180	0	0	0	0	0
Pipeline Fuel	252	247	243	282	299	386	374	361	418	439
Lease and Plant Fuel	76	168	208	204	190	117	254	309	302	278
Unaccounted For	18	33	44	41	34	27	50	66	61	50
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**6,486**	**6,676**	**6,688**	**7,718**	**8,295**	**9,174**	**9,885**	**9,870**	**10,256**	**10,130**

Table D–1L. (Continued)
Average January Day and Peak Day Demand by Region
Low Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
Midwest										
Residential	9,146	9,486	9,208	9,000	8,819	16,828	17,644	17,679	17,641	17,638
Commercial	4,663	4,706	4,696	4,984	5,020	8,393	8,470	8,453	8,971	9,036
Industrial										
Firm	1,053	996	852	799	708	1,664	1,573	1,346	1,263	1,119
Cogeneration	3	81	119	122	128	3	81	119	122	128
Interruptible	2,622	2,480	2,119	1,995	1,770	0	0	0	0	0
Electric Utility										
Firm	8	13	21	21	24	8	13	21	21	24
Combined Cycle	0	263	273	606	1,109	0	0	0	0	0
Interruptible	81	149	226	233	256	0	0	0	0	0
Pipeline Fuel	860	2,376	2,354	2,338	2,331	1,464	4,009	3,955	3,915	3,885
Lease and Plant Fuel	58	61	57	76	74	99	103	96	127	124
Unaccounted For	15	13	13	16	14	25	22	22	28	24
Exports	1,012	1,517	1,537	1,508	1,513	1,012	1,517	1,537	1,508	1,513
Total Demand	**18,509**	**20,823**	**19,938**	**20,191**	**20,253**	**28,485**	**31,915**	**31,690**	**32,087**	**31,979**
Southwest Central										
Residential	2,657	2,677	2,531	2,470	2,415	6,218	6,210	6,200	6,199	6,206
Commercial	1,380	1,460	1,433	1,577	1,641	2,677	2,832	2,781	3,059	3,183
Industrial										
Firm	6,589	6,707	6,171	5,925	5,456	7,907	8,048	7,405	7,110	6,547
Cogeneration	72	63	125	150	178	72	63	125	150	178
Interruptible	1,489	1,516	1,393	1,338	1,232	0	0	0	0	0
Electric Utility										
Firm	2,139	2,119	2,184	2,437	2,371	2,139	2,119	2,184	2,437	2,371
Combined Cycle	0	0	65	791	1751	0	0	0	0	0
Interruptible	516	511	527	588	572	0	0	0	0	0
Pipeline Fuel	446	902	1,099	1,370	1,590	546	1,104	1,345	1,674	1,941
Lease and Plant Fuel	2,509	2,231	1,911	1,994	1,920	3,072	2,732	2,339	2,438	2,343
Unaccounted For	580	429	400	394	340	710	526	490	481	414
Exports	44	465	685	931	1,150	44	465	685	931	1,150
Total Demand	**18,376**	**18,615**	**17,839**	**19,032**	**19,465**	**23,341**	**23,634**	**22,869**	**23,548**	**23,183**

Table D–1L. (Continued)
Average January Day and Peak Day Demand by Region
Low Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
Central										
Residential	2,054	2,043	1,979	1,915	1,848	3,718	3,595	3,601	3,600	3,604
Commercial	1,101	1,091	1,080	1,144	1,148	1,817	1,801	1,782	1,888	1,894
Industrial										
Firm	250	257	238	230	206	364	376	347	335	301
Cogeneration	0	6	6	9	9	0	6	6	9	9
Interruptible	595	610	566	539	492	0	0	0	0	0
Electric Utility										
Firm	5	8	8	8	8	5	8	8	8	8
Combined Cycle	0	15	96	158	257	0	0	0	0	0
Interruptible	27	33	43	42	43	0	0	0	0	0
Pipeline Fuel	204	198	194	195	190	323	315	306	308	299
Lease and Plant Fuel	129	128	101	93	77	204	203	160	146	121
Unaccounted For	26	21	18	16	12	41	34	29	25	18
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**4,391**	**4,412**	**4,329**	**4,350**	**4,291**	**6,472**	**6,337**	**6,240**	**6,320**	**6,254**
North Central										
Residential	1,058	1,079	1,068	1,079	1,094	2,117	1,996	1,986	1,996	1,992
Commercial	683	687	680	730	756	1,352	1,361	1,347	1,446	1,496
Industrial										
Firm	99	109	105	102	92	131	145	140	136	122
Cogeneration	0	38	63	69	75	0	38	63	69	75
Interruptible	287	316	303	300	271	0	0	0	0	0
Electric Utility										
Firm	3	13	13	13	16	3	13	13	13	16
Combined Cycle	0	0	436	739	957	0	0	0	0	0
Interruptible	56	242	236	242	261	0	0	0	0	0
Pipeline Fuel	109	119	138	155	164	183	206	235	263	276
Lease and Plant Fuel	312	413	475	542	598	526	716	811	917	1,007
Unaccounted For	70	78	97	104	103	119	134	166	177	174
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**2,675**	**3,094**	**3,614**	**4,076**	**4,387**	**4,430**	**4,610**	**4,760**	**5,017**	**5,158**

Table D–1L. (Continued)
Average January Day and Peak Day Demand by Region
Low Reference Case
(Million Cubic Feet per Day)

Region and Sector	Average January Day					Peak Day				
	1991	1995	2000	2005	2010	1991	1995	2000	2005	2010
Pacific										
Residential	2,573	2,644	2,618	2,608	2,604	5,635	5,764	5,759	5,764	5,781
Commercial	1,178	1,103	1,132	1,244	1,244	1,919	1,798	1,845	2,028	2,028
Industrial										
Firm	756	718	750	641	561	907	862	900	769	673
Cogeneration	169	522	466	682	794	169	522	466	682	794
Interruptible	700	666	695	595	518	0	0	0	0	0
Electric Utility										
Firm	73	78	90	106	118	73	78	90	106	118
Combined Cycle	0	0	39	123	245	0	0	0	0	0
Interruptible	837	897	1,035	1,217	1,370	0	0	0	0	0
Pipeline Fuel	226	230	234	248	252	403	409	419	443	450
Lease and Plant Fuel	61	69	100	152	182	109	122	179	272	326
Unaccounted For	17	16	25	36	38	30	28	44	63	68
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**6,588**	**6,944**	**7,184**	**7,650**	**7,927**	**9,243**	**9,583**	**9,703**	**10,127**	**10,238**
Northwest										
Residential	417	427	414	401	391	1,076	964	957	963	961
Commercial	335	338	318	332	333	822	828	779	813	815
Industrial										
Firm	61	57	51	47	40	94	89	78	73	63
Cogeneration	0	34	63	88	116	0	34	63	88	116
Interruptible	339	309	280	257	223	0	0	0	0	0
Electric Utility										
Firm	0	0	0	0	0	0	0	0	0	0
Combined Cycle	0	0	0	104	225	0	0	0	0	0
Interruptible	0	0	0	0	0	0	0	0	0	0
Pipeline Fuel	47	45	43	47	50	73	70	66	71	74
Lease and Plant Fuel	0	0	1	1	1	1	1	1	2	2
Unaccounted For	0	0	0	0	0	0	0	0	0	0
Exports	0	0	0	0	0	0	0	0	0	0
Total Demand	**1,200**	**1,212**	**1,169**	**1,278**	**1,380**	**2,066**	**1,986**	**1,945**	**2,010**	**2,032**

Table D–2.

Factors For Estimating Average January Day Demand from Annual Projections

Sector	New England	NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest
High and Low Reference Case										
Residential	0.0055	0.00557	0.00574	0.00616	0.00601	0.00627	0.00632	0.00531	0.00462	0.00505
Commercial	0.00486	0.00489	0.00522	0.00506	0.00585	0.00489	0.0052	0.00521	0.00356	0.00457
Industrial										
Firm	0.0037	0.00453	0.00492	0.0038	0.00493	0.00276	0.00408	0.0035	0.00275	0.00347
Cogeneration	0.00322	0.00322	0.00322	0.00322	0.00322	0.00322	0.00322	0.00322	0.00322	0.00322
Interruptible	0.00148	0.002	0.00249	0.00223	0.00277	0.00259	0.00271	0.00276	0.00263	0.00255
Electric Utility										
Firm	0	0.00274	0.00274	0.00274	0.00274	0.00185	0.00274	0.00274	0.00202	0.00024
Interruptible	0.00003	0.00036	0.00035	0.00115	0.00233	0.00165	0.00104	0.00639	0.00176	0
High Reference Case										
Electric Utility										
Combined Cycle										
1991	0	0	0	0	0	0	0	0	0	0
1995	0.00494	0.00503	0.00534	0.00534	0.00535	0	0.00494	0	0	0
2000	0.00496	0.00491	0.00781	0.00542	0.00772	0.00494	0.00776	0.00455	0.00606	0.01498
2005	0.00438	0.00403	0.00777	0.00782	0.00797	0.00491	0.00774	0.00494	0.00524	0.00778
2010	0.00364	0.00361	0.00777	0.00782	0.00823	0.00542	0.00776	0.00532	0.00476	0.00775
Low Reference Case										
Electric Utility										
Combined Cycle										
1991	0	0	0	0	0	0	0	0	0	0
1995	0.00523	0.00507	0.00547	0	0.00542	0	0.00501	0	0	0
2000	0.00529	0.0047	0.00767	0.00573	0.0076	0.00372	0.00762	0.00436	0.00501	0.00666
2005	0.00476	0.00369	0.00761	0.00771	0.00761	0.00455	0.00741	0.00464	0.00395	0.00767
2010	0.00438	0.00308	0.00757	0.00767	0.00793	0.00452	0.00736	0.00498	0.00383	0.00773

Source: Separate memos from EEA for the High and Low Reference Cases, both dated August 24, 1992, from Mark Breese

Table D–3.

Factors for Estimating Peak Day Demand from Average January Day Estimates

Sector		New England	NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest
Residential											
	1991	1.89	1.66	1.80	2.09	1.84	2.34	1.81	2.00	2.19	2.58
	1995	1.65	1.74	1.98	2.32	1.99	2.49	1.95	2.05	2.32	2.98
	2000	1.53	1.75	2.05	2.46	2.03	2.64	1.98	2.06	2.34	3.22
	2005	1.40	1.75	2.10	2.58	2.07	2.74	2.01	2.02	2.33	3.43
	2010	1.30	1.74	2.15	2.70	2.12	2.84	2.06	1.99	2.34	3.65
Commercial		1.85	1.60	1.75	1.98	1.80	1.94	1.65	1.98	1.63	2.45
Industrial											
Firm		1.36	1.43	1.63	1.55	1.58	1.20	1.46	1.33	1.20	1.55
Cogeneration		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Interruptible		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Utility											
Firm		0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Combined Cycle		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interruptible		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

===========

Source: Separate memos from EEA for the High and Low Reference Cases, both dated August 24, 1992, from Mark Breese

Table D–4H.
Production: Average Day, Average January Day, and Peak Day
High Reference Case
(Million Cubic Feet per Day)

Average Day

Region	1991	1995	2000	2005	2010
New England	0	0	0	0	0
NY/NJ	72	65	74	81	87
Middle Atlantic	1,336	1,201	1,361	1,492	1,598
South Atlantic	1,453	2,962	3,891	3,801	3,915
Midwest	1,172	1,159	1,415	1,444	1,552
Southwest Central	46,450	39,272	37,689	38,914	35,620
Central	1,949	1,833	1,635	1,469	1,111
North Central	5,456	7,153	8,298	9,215	11,849
Pacific	1,199	1,243	1,757	2,522	3,145
Northwest	9	10	13	21	27
Total	59,095	54,896	56,131	58,957	58,902

Average January Day a/

Region	1991	1995	2000	2005	2010
New England	0	0	0	0	0
NY/NJ	71	63	72	79	84
Middle Atlantic	1,302	1,171	1,327	1,454	1,558
South Atlantic	1,417	2,888	3,794	3,706	3,817
Midwest	1,143	1,130	1,379	1,408	1,513
Southwest Central	45,288	38,291	36,746	37,941	34,729
Central	1,900	1,787	1,594	1,432	1,084
North Central	5,319	6,974	8,091	8,985	11,553
Pacific	1,169	1,212	1,713	2,459	3,066
Northwest	9	9	13	20	26
Total	57,618	53,524	54,727	57,483	57,430

Peak Day b/

Region	1991	1995	2000	2005	2010
Southwest Central	43,431	36,720	35,239	36,385	33,304
Central	1,871	1,759	1,569	1,410	1,067

a/ Average January day production is average day production reduced by 2.5% in each region.
b/ Peak day production is equal to average January day production in all regions except the Southwest Central and Central regions. Peak day production is average day production reduced by 6.5% in the Southwest Central region and reduced by 4.0% in the Central region.

Source: Reduction factors from memo from Brad Defenbaugh of March 9, 1992.

Table D–4L.

Production: Average Day, Average January Day, and Peak Day
Low Reference Case
(Million Cubic Feet per Day)

Average Day

Region	1991	1995	2000	2005	2010
New England	0	0	0	0	0
NY/NJ	72	66	68	77	76
Middle Atlantic	1,325	1,214	1,265	1,416	1,413
South Atlantic	1,461	2,962	3,607	3,458	3,170
Midwest	1,161	1,114	1,030	1,333	1,290
Southwest Central	46,290	37,826	31,868	32,544	30,864
Central	1,956	1,779	1,388	1,240	1,015
North Central	5,493	6,697	7,577	8,455	9,191
Pacific	1,196	1,236	1,774	2,641	3,119
Northwest	9	9	14	22	26
Total	58,964	52,904	48,591	51,186	50,164

Average January Day a/

Region	1991	1995	2000	2005	2010
New England	0	0	0	0	0
NY/NJ	70	64	67	75	75
Middle Atlantic	1,292	1,183	1,233	1,381	1,378
South Atlantic	1,425	2,888	3,517	3,371	3,090
Midwest	1,132	1,087	1,005	1,300	1,258
Southwest Central	45,132	36,881	31,071	31,730	30,092
Central	1,907	1,735	1,353	1,209	989
North Central	5,356	6,530	7,387	8,243	8,961
Pacific	1,166	1,205	1,730	2,575	3,041
Northwest	9	9	13	21	26
Total	57,489	51,581	47,376	49,906	48,910

Peak Day b/

Region	1991	1995	2000	2005	2010
Southwest Central	43,281	35,367	29,796	30,429	28,858
Central	1,878	1,708	1,332	1,190	974

a/ Average January day production is average day production reduced by 2.5% in each region.
b/ Peak day production is equal to average January day production in all regions except the Southwest Central and Central regions. Peak day production is average day production reduced by 6.5% in the Southwest Central region and reduced by 4.0% in the Central region.

Source: Reduction factors from memo from Brad Defenbaugh of March 9, 1992.

Table D–5H.
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
High Reference Case

		1991									
		Annual Production by Demand Region (Bcf)									
Annual Production by Hydrocarbon Region (Bcf)		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	645	21	393	71	159						645
B	278			278							278
C	186				186						186
D	1,320					1,320					1,320
E	1,071					1,071					1,071
G	2,131					2,131					2,131
WL	102							102			102
FR	827							827			827
SJ	499							499			499
OV	179							179			179
JN	3,243					2,669	574				3,243
JS	1,421					1,421					1,421
L	306								303	3	306
NOR	79			79							79
EGO	5,070					5,070					5,070
LO	50								50		50
Total Annual Production	**17,407**	**21**	**393**	**428**	**345**	**13,682**	**574**	**1,607**	**353**	**3**	**17,407**
Daily Production a/ (MMcf/d)	59,096	72	1,336	1,453	1,172	46,450	1,949	5,456	1,199	9	59,096

a/ Daily production equals annual production divided by the utilization factor of 0.807 and by 0.365.

Table D–5H. (Continued)
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
High Reference Case

		1995									
		Annual Production by Demand Region (Bcf)									
Annual Production by Hydrocarbon Region (Bcf)		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	635	21	387	70	157						**635**
B	432			432							**432**
C	217				217						**217**
D	1,261					1,261					**1,261**
E	991					991					**991**
G	1,862					1,862					**1,862**
WL	115							115			**115**
FR	935							935			**935**
SJ	1,009							1,009			**1,009**
OV	249							249			**249**
JN	3,341					2,750	591				**3,341**
JS	1,356					1,356					**1,356**
L	339								336	3	**339**
NOR	454			454							**454**
EGO	4,452					4,452					**4,452**
LO	65								65		**65**
Total Annual Production	**17,713**	**21**	**387**	**956**	**374**	**12,672**	**591**	**2,308**	**401**	**3**	**17,713**
Daily Production b/ (MMcf/d)	54,897	65	1,200	2,962	1,159	39,272	1,833	7,153	1,243	9	**54,897**

b/ Daily production equals annual production divided by the utilization factor of 0.884 and by 0.365.

Table D–5H. (Continued)
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
High Reference Case

2000											
		Annual Production by Demand Region (Bcf)									
Annual Production by Hydrocarbon Region (Bcf)		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	736	24	449	81	182						**736**
B	549			549							**549**
C	285				285						**285**
D	1,297					1,297					**1,297**
E	938					938					**938**
G	1,774					1,774					**1,774**
WL	113							113			**113**
FR	934							934			**934**
SJ	1,322							1,322			**1,322**
OV	369							369			**369**
JN	3,047					2,508	539				**3,047**
JS	1,409					1,409					**1,409**
L	487								483	4	**487**
NOR	654			654							**654**
EGO	4,510					4,510					**4,510**
LO	97								97		**97**
Total Annual Production	**18,521**	**24**	**449**	**1,284**	**467**	**12,436**	**539**	**2,738**	**580**	**4**	**18,521**
Daily Production c/ (MMcf/d)	56,131	74	1,361	3,891	1,415	37,688	1,634	8,298	1,757	13	**56,131**

c/ Daily production equals annual production divided by the utilization factor of 0.904 and by 0.365.

Table D–5H. (Continued)
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
High Reference Case

2005

Annual Production by Hydrocarbon Region (Bcf)		Annual Production by Demand Region (Bcf)									
		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	830	27	506	91	205						**830**
B	634			634							**634**
C	285				285						**285**
D	1,207					1,207					**1,207**
E	875					875					**875**
G	2,272					2,272					**2,272**
WL	114							114			**114**
FR	1,104							1,104			**1,104**
SJ	1,431							1,431			**1,431**
OV	479							479			**479**
JN	2,817					2,318	499				**2,817**
JS	1,583					1,583					**1,583**
L	780								773	7	**780**
NOR	565			565							**565**
EGO	4,954					4,954					**4,954**
LO	83								83		**83**
Total Annual Production	**20,013**	**27**	**506**	**1,290**	**490**	**13,209**	**499**	**3,128**	**856**	**7**	**20,013**
Daily Production d/ (MMcf/d)	58,957	81	1,492	3,801	1,444	38,914	1,469	9,215	2,522	21	**58,957**

d/ Daily production equals annual production divided by the utilization factor of 0.930 and by 0.365.

Table D–5H. (Continued)
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
High Reference Case

2010

Annual Production by Hydrocarbon Region (Bcf)		Annual Production by Demand Region (Bcf) NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	898	30	548	99	222						**898**
B	779			779							**779**
C	310				310						**310**
D	1,518					1,518					**1,518**
E	715					715					**715**
G	2,133					2,133					**2,133**
WL	118							118			**118**
FR	1,812							1,812			**1,812**
SJ	1,540							1,540			**1,540**
OV	591							591			**591**
JN	2,152					1,771	381				**2,152**
JS	1,590					1,590					**1,590**
L	1,011								1,002	9	**1,011**
NOR	464			464							**464**
EGO	4,481					4,481					**4,481**
LO	76								76		**76**
Total Annual Production	**20,188**	**30**	**548**	**1,342**	**532**	**12,208**	**381**	**4,061**	**1,078**	**9**	**20,188**
Daily Production e/ (MMcf/d)	58,903	86	1,598	3,915	1,552	35,620	1,111	11,849	3,145	27	**58,903**

e/ Daily production equals annual production divided by the utilization factor of 0.939 and by 0.365.
Source: NPC High Reference Case.

Table D–5L.
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
Low Reference Case

1991

Annual Production by Hydrocarbon Region (Bcf)		Annual Production by Demand Region (Bcf)									
		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	640	21	390	70	158						640
B	281			281							281
C	184				184						184
D	1,330					1,330					1,330
E	1,067					1,067					1,067
G	2,136					2,136					2,136
WL	102							102			102
FR	829							829			829
SJ	508							508			508
OV	179							179			179
JN	3,255					2,679	576				3,255
JS	1,431					1,431					1,431
L	305								302	3	305
NOR	79			79							79
EGO	4,992					4,992					4,992
LO	50								50		50
Total Annual Production	**17,368**	**21**	**390**	**430**	**342**	**13,635**	**576**	**1,618**	**352**	**3**	**17,368**
Daily Production a/ (MMcf/d)	58,964	72	1,325	1,461	1,161	46,290	1,956	5,493	1,196	9	**58,964**

a/ Daily production equals annual production divided by the utilization factor of 0.807 and by 0.365.

Table D–5L. (Continued)
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
Low Reference Case

1995											
Annual Production by Hydrocarbon Region (Bcf)		Annual Production by Demand Region (Bcf)									
		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	642	21	392	71	159						**642**
B	427			427							**427**
C	201				201						**201**
D	1,208					1,208					**1,208**
E	988					988					**988**
G	1,836					1,836					**1,836**
WL	108							108			**108**
FR	871							871			**871**
SJ	934							934			**934**
OV	248							248			**248**
JN	3,243					2,669	574				**3,243**
JS	1,345					1,345					**1,345**
L	340								337	3	**340**
NOR	458			458							**458**
EGO	4,159					4,159					**4,159**
LO	62								62		**62**
Total Annual Production	**17,070**	**21**	**392**	**956**	**360**	**12,205**	**574**	**2,161**	**399**	**3**	**17,070**
Daily Production b/ (MMcf/d)	52,904	66	1,214	2,962	1,114	37,826	1,779	6,697	1,236	9	**52,904**

b/ Daily production equals annual production divided by the utilization factor of 0.884 and by 0.365.

Table D–5L. (Continued)
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
Low Reference Case

		2000									
		Annual Production by Demand Region (Bcf)									
Annual Production by Hydrocarbon Region (Bcf)		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	684	23	417	75	169						**684**
B	484			484							**484**
C	171				171						**171**
D	958					958					**958**
E	883					883					**883**
G	1,604					1,604					**1,604**
WL	101							101			**101**
FR	846							846			**846**
SJ	1,198							1,198			**1,198**
OV	355							355			**355**
JN	2,587					2,129	458				**2,587**
JS	1,362					1,362					**1,362**
L	500								496	5	**500**
NOR	631			631							**631**
EGO	3,579					3,579					**3,579**
LO	90								90		**90**
Total Annual Production	**16,033**	**23**	**417**	**1,190**	**340**	**10,515**	**458**	**2,500**	**586**	**5**	**16,033**
Daily Production c/ (MMcf/d)	48,591	68	1,265	3,607	1,030	31,868	1,388	7,577	1,774	14	**48,591**

c/ Daily production equals annual production divided by the utilization factor of 0.904 and by 0.365.

Table D–5L. (Continued)
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
Low Reference Case

		2005									
		Annual Production by Demand Region (Bcf)									
Annual Production by Hydrocarbon Region (Bcf)		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	788	26	481	87	195						**788**
B	524			524							**524**
C	258				258						**258**
D	977					977					**977**
E	722					722					**722**
G	1,877					1,877					**1,877**
WL	106							106			**106**
FR	1,011							1,011			**1,011**
SJ	1,271							1,271			**1,271**
OV	482							482			**482**
JN	2,378					1,957	421				**2,378**
JS	1,527					1,527					**1,527**
L	821								814	7	**821**
NOR	563			563							**563**
EGO	3,987					3,987					**3,987**
LO	83								83		**83**
Total Annual Production	**17,375**	**26**	**481**	**1,174**	**453**	**11,047**	**421**	**2,870**	**897**	**7**	**17,375**
Daily Production d/ (MMcf/d)	51,186	77	1,416	3,458	1,333	32,544	1,240	8,455	2,641	22	**51,186**

d/ Daily production equals annual production divided by the utilization factor of 0.930 and by 0.365.

Table D–5L. (Continued)
Conversion of Annual Production by Hydrocarbon Region to Maximum Daily Production by Demand Region
Low Reference Case

2010											
Annual Production by Hydrocarbon Region (Bcf)		Annual Production by Demand Region (Bcf)									
		NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
A	794	26	484	87	196						794
B	530			530							530
C	246				246						246
D	1,060					1,060					1,060
E	665					665					665
G	1,920					1,920					1,920
WL	101							101			101
FR	1,256							1,256			1,256
SJ	1,227							1,227			1,227
OV	566							566			566
JN	1,965					1,617	348				1,965
JS	1,362					1,362					1,362
L	1,000								991	9	1,000
NOR	469			469							469
EGO	3,954					3,954					3,954
LO	78								78		78
Total Annual Production	**17,193**	**26**	**484**	**1,086**	**442**	**10,578**	**348**	**3,150**	**1,069**	**9**	**17,193**
Daily Production e/ (MMcf/d)	50,164	76	1,413	3,170	1,290	30,864	1,015	9,191	3,119	26	**50,164**

e/ Daily production equals annual production divided by the utilization factor of 0.939 and by 0.365.
Source: NPC Low Reference Case.

TABLE D–6H
Natural Gas Import Capacities: Source Data and Levels Assumed in Analysis High Reference Case (Million Cubic Feet per Day)

Proposed Import Capacities

Region	1989	1990	1991	1992
New England	32	NA	32	32
NY/NJ	268	NA	743	1,341
Midwest	1,924	NA	2,085	2,503
Southwest Central	370	NA	370	370
North Central	1,075	NA	1,225	1,480
Northwest	2,372	NA	2,372	2,372

EEA Import Flows at 100% Utilization a/

Region	1989	1990	1991	1992	1995	2000	2005	2010
New England	NA	0	NA	NA	0	0	0	0
NY/NJ	NA	368	NA	NA	1,284	1,214	1,287	2,117
Midwest	NA	1,921	NA	NA	2,567	2,449	2,682	2,819
Southwest Central	NA	0	NA	NA	0	0	0	304
North Central	NA	1,074	NA	NA	1,780	2,478	2,478	2,879
Northwest	NA	2,103	NA	NA	3,026	3,157	3,327	3,639

Import Capacities Assumed in Analysis b/

Region	1991	1992	1993-1995	1996-2000	2001-2005	2006-2010
New England	32	32	32	32	32	32
NY/NJ	743	1,341	1,341	1,341	1,341	2,117
Midwest	2,085	2,503	2,567	2,567	2,682	2,819
Southwest Central	370	370	370	370	370	370
North Central	1,225	1,480	1,780	2,478	2,478	2,879
Northwest	2,372	2,372	3,026	3,157	3,327	3,639

NA=Not available.

a/ EEA import flows were provided by entry point at 90% utilization. These data were aggregated into Demand Regions and increased to 100% utilization.

b/ FERC capacities were used for 1991 and 1992. For 1993-2010, the maximum of the FERC capacity and the 100% EEA flow was used. If this maximum in any year was any lower than in the previos year, the previous year's value was used.

Sources: Proposed Import Capacities: Appendix C, Existing System Study, Tables 2-4.
EEA Import Flows: Memo of August 31, 1992 from Robert Crawford.

Table D–6L
Natural Gas Import Capacities: Source Data and Levels Assumed in Analysis
Low Reference Case
(Million Cubic Feet per Day)

Proposed Import Capacities

Region	1989	1990	1991	1992
New England	32	NA	32	32
NY/NJ	268	NA	743	1,341
Midwest	1,924	NA	2,085	2,503
Southwest Central	370	NA	370	370
North Central	1,075	NA	1,225	1,480
Northwest	2,372	NA	2,372	2,372

EEA Import Flows at 100% Utilization a/

Region	1989	1990	1991	1992	1995	2000	2005	2010
New England	NA	0	NA	NA	0	0	0	0
NY/NJ	NA	368	NA	NA	1,284	1,214	1,331	1,332
Midwest	NA	1,921	NA	NA	2,568	2,449	2,432	2,678
Southwest Central	NA	0	NA	NA	0	0	0	0
North Central	NA	1,074	NA	NA	1,780	2,478	2,478	2,778
Northwest	NA	2,106	NA	NA	3,102	2,880	2,873	3,098

Import Capacities Assumed in Analysis b/

Region	1991	1992	1995	2000	2005	2010
New England	32	32	32	32	32	32
NY/NJ	743	1,341	1,341	1,341	1,341	1,341
Midwest	2,085	2,503	2,568	2,568	2,568	2,678
Southwest Central	370	370	370	370	370	370
North Central	1,225	1,480	1,780	2,478	2,478	2,778
Northwest	2,372	2,372	3,102	3,102	3,102	3,102

NA=Not available.

a/ EEA import flows were provided by entry point at 90% utilization. These data were aggregated into Demand Regions and increased to 100% utilization.

b/ FERC capacities were used for 1991 and 1992. For 1993-2010, the maximum of the FERC capacity and the 100% EEA flow was used. If this maximum in any year was any lower than in the previos year, the previous year's value was use

Sources: Proposed Import Capacities: Appendix C, Existing System Study, Tables 2-4.
EEA Import Flows: Memo of August 31, 1992 from Robert Crawford.

Table D–7.

LNG Capacity Assumptions, 1991-2010
(Million Cubic Feet per Day)

Region	Facility	Average January Day	Peak Day
New England	Everett		
1990-1992		240	280
1993-2010		315	360
Southwest Central	Lake Charles	600	700

Source: Memo from Deborah Plattsmier of February 24, 1992.
"Current Sustainable & Peak LNG Import Capacity and Planned Additions Through 2010."

TABLE D–8

Underground Storage, 1991
(Million Cubic Feet per Day)

Region	Average January Day	Peak Day
New England	0	0
New York/New Jersey	537	1,008
Middle Atlantic	5,583	11,269
South Atlantic	1,300	3,395
Midwest	7,185	17,792
Southwest Central	4,445	10,058
Central	1,789	2,713
North Central	683	1,870
Pacific	1,457	5,100
Northwest	178	450
Total U.S.	**23,157**	**53,655**

Sources: Average January Day: The highest monthly withdrawal rate that occurred between January 1985 and December 1990. These monthly rates are from Jensen Associates, Inc., 1985-1990 Monthly Data Series on Gas Consumption, Storage, & Production by Federal Regions, September 1991. Peak Day: Appendix C, Existing System Study, Table 7.

TABLE D–9

Peak Shaving, 1991
(Million Cubic Feet per Day)

Region	Capacity	Level Assumed in Analysis
New England	1,827	433
New York/New Jersey	1,680	397
Middle Atlantic	2,005	473
South Atlantic	2,675	631
Midwest	2,783	657
Southwest Central	67	16
Central	861	203
North Central	33	8
Pacific	167	39
Northwest	601	142
Total U.S.	**12,699**	**2,999**

======================
Sources: Capacity: Sum of propane air and liquefied natural gas from GRI, Propane-Air Peakshaving Facilities in the United States, January 1992, and LNG Peakshaving Facilities in the United States, January 1992. Level Assumed in Analysis: AGA.

Table D–10.

Interregional Pipeline Capacities (Million Cubic Feet per Day)

1991 Capacity

	To Regions										
	New England	NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
From Regions											
New England	0	0	0	0	0	0	0	0	0	0	0
NY/NJ	2,001	0	58	0	0	0	0	0	0	0	2,059
Middle Atlantic	0	8,148	0	24	995	0	0	0	0	0	9,167
South Atlantic	0	0	4,601	0	9,905	34	0	0	0	0	14,540
Midwest	0	0	4,501	0	0	0	1,528	0	0	0	6,029
Southwest Central	0	0	0	19,466	0	0	9,192	984	4,319	0	33,961
Central	0	0	0	0	7,252	160	0	360	0	0	7,772
North Central	0	0	0	0	1,363	1,084	1,040	0	0	324	3,811
Pacific	0	0	0	0	0	0	0	0	0	0	0
Northwest	0	0	0	0	0	0	0	259	1,258	0	1,517
Total	2,001	8,148	9,160	19,490	19,515	1,278	11,760	1,603	5,577	324	

Table D–10. (Continued)

Interregional Pipeline Capacities
(Million Cubic Feet per Day)

1992 Capacity Additions

	To Regions										
	New England	NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
From Regions											
New England	0	0	0	0	0	0	0	0	0	0	0
NY/NJ	343	0	125	0	0	0	0	0	0	0	468
Middle Atlantic	0	393	0	0	0	0	0	0	0	0	393
South Atlantic	0	0	0	0	112	0	0	0	0	0	112
Midwest	0	0	160	0	0	0	313	0	0	0	473
Southwest Central	0	0	0	100	0	0	0	0	746	0	846
Central	0	0	0	0	21	0	0	0	0	0	21
North Central	0	0	0	0	313	0	0	0	700	0	1,013
Pacific	0	0	0	0	0	0	0	0	0	0	0
Northwest	0	0	0	0	0	0	0	0	0	0	0
Total	343	393	285	100	446	0	313	0	1,446	0	

Table D–10. (Continued)

Interregional Pipeline Capacities
(Million Cubic Feet per Day)

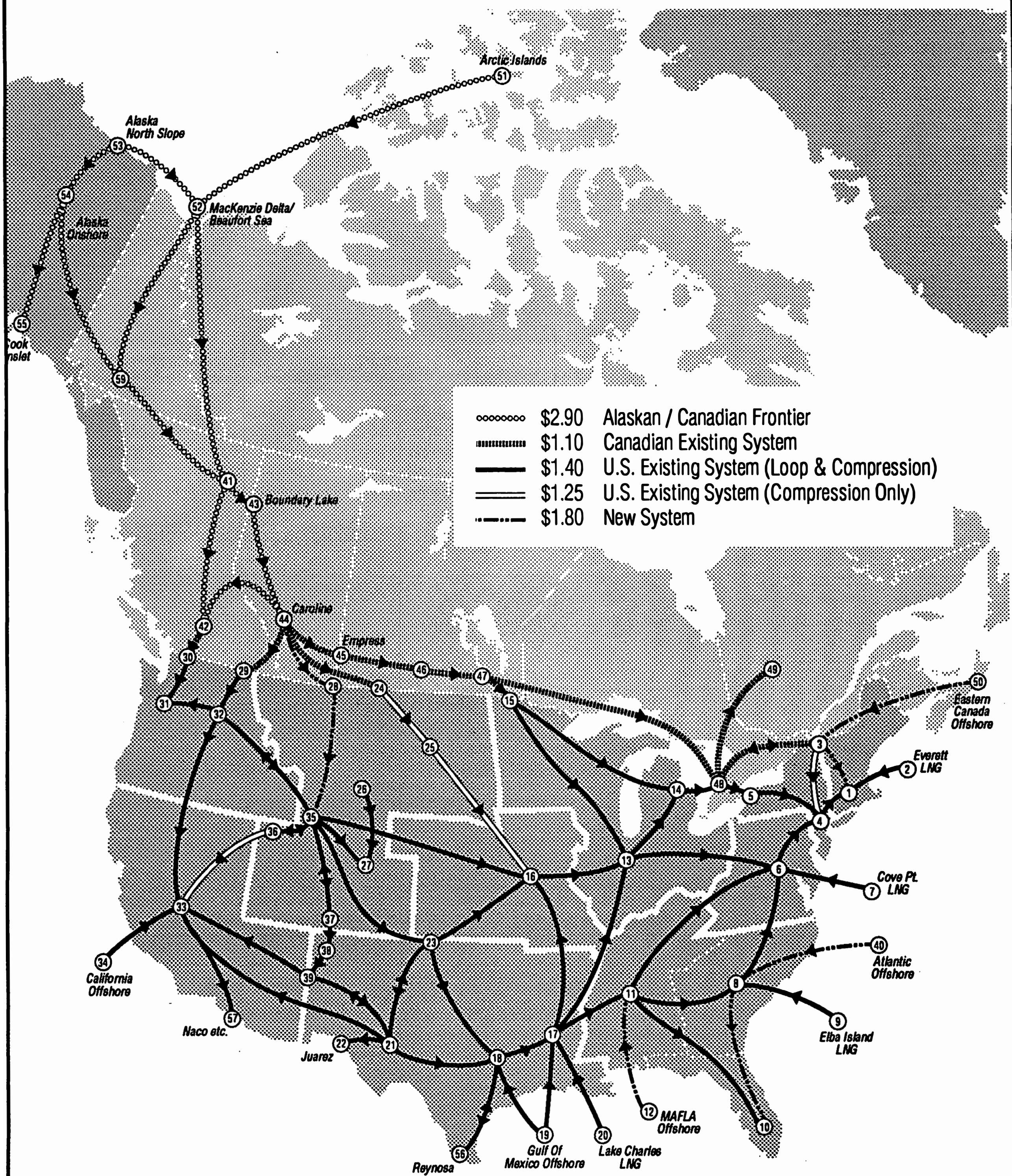
1992 Capacity

	To Regions										
	New England	NY/NJ	Middle Atlantic	South Atlantic	Midwest	Southwest Central	Central	North Central	Pacific	Northwest	Total
From Regions											
New England	0	0	0	0	0	0	0	0	0	0	0
NY/NJ	2,344	0	183	0	0	0	0	0	0	0	2,527
Middle Atlantic	0	8,541	0	24	995	0	0	0	0	0	9,560
South Atlantic	0	0	4,601	0	10,017	34	0	0	0	0	14,652
Midwest	0	0	4,661	0	0	0	1,841	0	0	0	6,502
Southwest Central	0	0	0	19,566	0	0	9,192	984	5,065	0	34,807
Central	0	0	0	0	7,273	160	0	360	0	0	7,793
North Central	0	0	0	0	1,676	1,084	1,040	0	700	324	4,824
Pacific	0	0	0	0	0	0	0	0	0	0	0
Northwest	0	0	0	0	0	0	0	259	1,258	0	1,517
Total	2,344	8,541	9,445	19,590	19,961	1,278	12,073	1,603	7,023	324	

Note: Adjustments made to 1992 capacity additions in original source data are (1) capacity from New York/New Jersey to New England is reduced by 205 million cubic feet per day and (2) capacity from Southwest Central to South Atlantic of 600 million cubic feet per day is not used. Source: Appendix C, Existing System Study, Table 8.

APPENDIX E

INVESTMENT ASSUMPTIONS



North American Gas Pipeline Network Structure

Transmission Capital Expenditure Relationship

— $/Mcfd/Mile —

INGAA

Memorandum to
Environment, Safety & Operations Committee

October 4, 1991

Subject: Estimate of Future Pipeline System Maintenance/
Replacement Program

The National Petroleum Council's Committee on Natural Gas is conducting a study for the Secretary of Energy, "Potential for Expanding Natural Gas Production, Distribution and Use". It is to be a comprehensive analysis addressing technical, economic and regulatory constraints; projected reserves; and future markets, imports and exports.

I am INGAA's representative on the Transportation and Storage Task Group, which includes representatives of several of your companies. We are now developing basic data about the existing pipeline and storage system and future plans to extend the life of that system through maintenance/replacement programs, to include meeting environmental requirements.

To assist us in that effort, I would appreciate information from you about your future plans. **Please complete the attached survey form to the best of your ability and return it to me by November 1, 1991.**

Ted

Theodore L. Kinne
Vice President
Environment, Safety & Operations

TLK/jda

Enclosure

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
555 13TH STREET, N.W., #300 W • WASHINGTON, D.C. 20004 • 202/626-3200

NATIONAL PETROLEUM COUNCIL STUDY
TRANSPORTATION AND STORAGE

____
(COMPANY)

____
(CONTACT PERSON & TELEPHONE NO.)

FUTURE MAINTENANCE/REPLACEMENT PROGRAM

Please complete, in 1991 dollars, your company's best estimate for the time periods shown. This is capital budget dollars, but not including supply or market expansion projects. It should, however, include compression modernization and replacement on the existing system.

CATEGORY	1991-2000	2001-2010	2011-2030
1. Capital $ million/ year for transmission plant replacements	________	________	________
2. Miles/year of transmission line to be replaced	________	________	________
3. Percent/year of company's transmission plant to be replaced	________	________	________
4. Percent/year of company's Annual Capital Budget	________	________	________
5. Current miles of Transmission Line	________		
6. Current Annual $/Year of Depreciation	________		

CONSTRUCTION EXPENDITURES – AGA GAS FACTS
(Millions of Dollars)

	TRANSMISSION	UNDERGROUND STORAGE	TOTAL	GDP 1991=100	1991 $
1971	842	171	1,013	31.62	3,203
1972	678	177	855	33.16	2,578
1973	746	201	947	35.81	2,644
1974	632	230	862	38.38	2,246
1975	590	276	866	42.05	2,059
1976	531	362	893	44.70	1,998
1977	670	323	993	47.78	2,078
1978	935	321	1,256	51.54	2,437
1979	1,226	281	1,507	55.98	2,692
1980	1,583	396	1,979	61.28	3,229
1981	2,352	326	2,678	67.44	3,971
1982	1,921	368	2,289	71.62	3,196
1983	1,065	139	1,204	74.53	1,615
1984	1,301	121	1,422	77.78	1,828
1985	1,562	175	1,737	80.68	2,153
1986	1,448	125	1,573	82.82	1,899
1987	1,295	107	1,402	85.47	1,640
1988	1,568	101	1,669	88.80	1,879
1989	2,081	159	2,240	92.65	2,418
1990	2,886	219	3,105	96.50	3,218
AVERAGE					$2,449

NPC PIPELINE SURVEY

FUTURE MAINTENANCE/REPLACEMENT PROGRAMS
(Millions of 1991 Dollars)

	1991-2000	2001-2010	AVG
CAPITAL $/MILLION/YEAR FOR TRANSMISSION PLANT MAINTENACE/REPLACEMENT	$1,092	$1,179	$1,136
MILES REPRESENTED IN SURVEY	190,620		
NUMBER OF COMPANIES RESPONDING	27		
TOTAL US TRANSMISSION MILEAGE	280,000		
ADJUSTED SURVEY RESULTS	$1,604	$1,732	$1,668

APPENDIX F
MODELING RESULTS

Reference Case 1
and
Reference Case 2

Region 1	New England
Region 2	New York/New Jersey
Region 3	Middle Atlantic
Region 4	South Atlantic
Region 5	Midwest
Region 6	Southwest Central
Region 7	Central
Region 8	North Central
Region 9	Pacific
Region 10	Northwest

NOTE: In this appendix, Reference Case 1 and Reference Case 2 are referred to as High and Low Reference Cases, respectively.

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 1991 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	455	1.00	1420	1.00	1152	1.00	955	1.00	4169	1.00	1161	1.00	891	1.00	546	1.00	1526	1.00	226	1.00	12501	1.00
Commercial	272	1.00	894	1.00	682	1.00	721	1.00	2183	1.00	773	1.00	580	1.00	359	1.00	906	1.00	201	1.00	7571	1.00
Industrial Firm	88	1.00	156	1.00	239	1.00	638	1.00	606	1.00	7021	1.00	180	1.00	87	1.00	930	1.00	50	1.00	9994	1.00
Elec Util Firm	28	1.00	33	1.00	26	1.00	243	1.00	141	1.00	3198	1.00	5	1.00	3	1.00	96	1.00	0	.00	3773	1.00
Ind Interrupt	106	1.00	398	1.00	932	1.00	1772	1.00	2666	1.00	1675	1.00	644	1.00	320	1.00	756	1.00	379	1.00	9646	1.00
Elec Interrupt	204	1.00	763	1.00	91	1.00	531	1.00	96	1.00	864	1.00	72	1.00	26	1.00	1274	1.00	37	1.00	3956	1.00
Fuel	45	1.00	146	1.00	201	1.00	278	1.00	452	1.00	3372	1.00	210	1.00	384	1.00	285	1.00	35	1.00	5407	1.00
Total Demand	1197	1.00	3808	1.00	3322	1.00	5137	1.00	10313	1.00	18062	1.00	2582	1.00	1725	1.00	5772	1.00	928	1.00	52850	1.00
SUPPLIES																						
Production	0	.00	72	1.00	1336	1.00	1453	1.00	1172	1.00	46450	.87	1949	1.00	5456	.74	1199	1.00	9	1.00	59095	.87
Imports	32	.00	743	.00	0	.00	0	.00	2085	.00	370	.00	0	.00	1225	.00	0	.00	2372	.61	6827	.21
Base Load LNG	240	.00	0	.00	0	.00	0	.00	0	.00	600	.00	0	.00	0	.00	0	.00	0	.00	840	.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	272	.00	815	.09	1335	1.00	1452	1.00	3257	.36	47419	.85	1948	1.00	6680	.60	1199	1.00	2381	.61	66762	.79
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2001	.60	0	.00	58	.28	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2059	.59
From 3	0	.00	8148	.61	0	.00	24	.00	995	.54	0	.00	0	.00	0	.00	0	.00	0	.00	9167	.60
From 4	0	.00	0	.00	4601	1.00	0	.00	9905	.74	34	.15	0	.00	0	.00	0	.00	0	.00	14540	.82
From 5	0	.00	0	.00	4501	.63	0	.00	0	.00	0	.00	1528	.57	0	.00	0	.00	0	.00	6029	.62
From 6	0	.00	0	.00	0	.00	19466	.80	0	.00	0	.00	9192	.33	984	.13	4319	.86	0	.00	33961	.66
From 7	0	.00	0	.00	0	.00	0	.00	7252	.50	160	.15	0	.00	360	.52	0	.00	0	.00	7772	.49
From 8	0	.00	0	.00	0	.00	0	.00	1363	1.00	1084	.35	1040	.52	0	.00	0	.00	324	1.00	3811	.68
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.68	0	.00	1517	.56
Total PL In	2001	.60	8148	.61	9160	.82	19490	.80	19515	.66	1278	.32	11760	.38	1603	.20	5577	.82	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2001	.60	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2001	.60
To 2	0	.00	0	.00	8148	.61	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8148	.61
To 3	0	.00	58	.28	0	.00	4601	1.00	4501	.63	0	.00	0	.00	0	.00	0	.00	0	.00	9160	.82
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19466	.80	0	.00	0	.00	0	.00	0	.00	19490	.80
To 5	0	.00	0	.00	995	.54	9905	.74	0	.00	0	.00	7252	.50	1363	1.00	0	.00	0	.00	19515	.66
To 6	0	.00	0	.00	0	.00	34	.15	0	.00	0	.00	160	.15	1084	.35	0	.00	0	.00	1278	.32
To 7	0	.00	0	.00	0	.00	0	.00	1528	.57	9192	.33	0	.00	1040	.52	0	.00	0	.00	11760	.38
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.13	360	.52	0	.00	0	.00	259	.00	1603	.20
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	4319	.86	0	.00	0	.00	0	.00	1258	.68	5577	.82
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2059	.59	9167	.60	14540	.82	6029	.62	33961	.66	7772	.49	3811	.68	0	.00	1517	.56		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 1991 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	913	1.00	2888	1.00	2414	1.00	2148	1.00	9145	1.00	2657	1.00	2054	1.00	1058	1.00	2572	1.00	417	1.00	26267	1.00
Commercial	483	1.00	1595	1.00	1299	1.00	1331	1.00	4662	1.00	1380	1.00	1101	1.00	683	1.00	1177	1.00	335	1.00	14046	1.00
Industrial Firm	119	1.00	225	1.00	439	1.00	847	1.00	1056	1.00	6650	1.00	250	1.00	99	1.00	922	1.00	61	1.00	10666	1.00
Elec Util Firm	0	.00	3	1.00	5	1.00	221	1.00	8	1.00	2139	1.00	5	1.00	3	1.00	73	1.00	0	.00	2456	1.00
Ind Interrupt	58	1.00	258	1.00	897	1.00	1388	1.00	2614	1.00	1486	1.00	592	1.00	287	1.00	697	1.00	339	1.00	8615	1.00
Elec Interrupt	2	1.00	98	1.00	11	1.00	202	1.00	81	1.00	516	1.00	27	1.00	56	1.00	837	1.00	0	.00	1830	1.00
Fuel	69	1.00	211	1.00	340	1.00	347	1.00	933	1.00	3533	1.00	358	1.00	489	1.00	304	1.00	47	1.00	6630	1.00
Total Demand	1642	1.00	5277	1.00	5405	1.00	6484	1.00	18499	1.00	18360	1.00	4387	1.00	2674	1.00	6581	1.00	1199	1.00	70512	1.00
SUPPLIES																						
Production	0	.00	71	1.00	1302	1.00	1417	1.00	1143	1.00	45288	1.00	1900	1.00	5319	1.00	1169	1.00	9	1.00	57618	1.00
Imports	32	1.00	743	1.00	0	.00	0	.00	2085	1.00	370	1.00	0	.00	1225	.50	0	.00	2372	1.00	6827	.91
Base Load LNG	240	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	840	1.00
Storage	0	.00	537	1.00	5583	.75	1300	.00	7185	.15	4445	.00	1789	.00	683	.00	1457	.00	178	.00	23157	.25
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	272	1.00	1350	1.00	6885	.80	2716	.52	10413	.42	50703	.91	3689	.52	7227	.82	2626	.45	2559	.93	88442	.80
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2001	.68	0	.00	58	.28	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2059	.67
From 3	0	.00	8148	.65	0	.00	24	.00	995	.54	0	.00	0	.00	0	.00	0	.00	0	.00	9167	.64
From 4	0	.00	0	.00	4601	.67	0	.00	9905	.86	34	.15	0	.00	0	.00	0	.00	0	.00	14540	.80
From 5	0	.00	0	.00	4501	.59	0	.00	0	.00	0	.00	1528	.57	0	.00	0	.00	0	.00	6029	.59
From 6	0	.00	0	.00	0	.00	19466	.86	0	.00	0	.00	9192	.87	984	.13	4319	.96	0	.00	33961	.85
From 7	0	.00	0	.00	0	.00	0	.00	7252	1.00	160	.15	0	.00	360	.52	0	.00	0	.00	7772	.96
From 8	0	.00	0	.00	0	.00	0	.00	1363	1.00	1084	1.00	1040	1.00	0	.00	0	.00	324	.26	3811	.94
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2001	.68	8148	.65	9160	.63	19490	.86	19515	.91	1278	.87	11760	.85	1603	.20	5577	.97	324	.26		
PIPELINE FLOW OUT																						
To 1	0	.00	2001	.68	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2001	.68
To 2	0	.00	0	.00	8148	.65	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8148	.65
To 3	0	.00	58	.28	0	.00	4601	.67	4501	.59	0	.00	0	.00	0	.00	0	.00	0	.00	9160	.63
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19466	.86	0	.00	0	.00	0	.00	0	.00	19490	.86
To 5	0	.00	0	.00	995	.54	9905	.86	0	.00	0	.00	7252	1.00	1363	1.00	0	.00	0	.00	19515	.91
To 6	0	.00	0	.00	0	.00	34	.15	0	.00	0	.00	160	.15	1084	1.00	0	.00	0	.00	1278	.87
To 7	0	.00	0	.00	0	.00	0	.00	1528	.57	9192	.87	0	.00	1040	1.00	0	.00	0	.00	11760	.85
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.13	360	.52	0	.00	0	.00	259	.00	1603	.20
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	4319	.96	0	.00	0	.00	0	.00	1258	1.00	5577	.97
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.26	0	.00	0	.00	324	.26
Total PL Out	0	.00	2059	.67	9167	.64	14540	.80	6029	.59	33961	.85	7772	.96	3811	.94	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 1991 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1726	1.00	4794	1.00	4346	1.00	4489	1.00	16827	1.00	6218	1.00	3718	1.00	2117	1.00	5634	1.00	1077	1.00	50943	1.00
Commercial	893	1.00	2552	1.00	2274	1.00	2636	1.00	8391	1.00	2677	1.00	1816	1.00	1352	1.00	1919	1.00	822	1.00	25331	1.00
Industrial Firm	161	.11	318	1.00	698	1.00	1298	1.00	1667	1.00	7966	1.00	364	1.00	131	1.00	1072	1.00	94	1.00	13768	.99
Elec Util Firm	0	.00	3	1.00	5	1.00	221	1.00	8	1.00	2139	1.00	5	1.00	3	1.00	73	1.00	0	.00	2456	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	112	1.00	346	1.00	667	1.00	531	1.00	1588	1.00	4326	1.00	567	1.00	826	1.00	541	1.00	73	1.00	9577	1.00
Total Demand	2891	.95	8012	1.00	7989	1.00	9174	1.00	28480	1.00	23325	1.00	6470	1.00	4428	1.00	9238	1.00	2065	1.00	102078	1.00
SUPPLIES																						
Production	0	.00	71	1.00	1302	1.00	1417	1.00	1143	1.00	43431	1.00	1871	1.00	5319	1.00	1169	1.00	9	1.00	55731	1.00
Imports	32	1.00	743	1.00	0	.00	0	.00	2085	1.00	370	1.00	0	.00	1225	1.00	0	.00	2372	1.00	6827	1.00
Base Load LNG	280	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	980	1.00
Storage	0	.00	1008	1.00	11269	1.00	3395	.61	17792	1.00	10058	.00	2713	.36	1870	.00	5100	.87	450	.80	53655	.71
Peak Shaving	1827	.24	1680	.03	2005	.00	2675	.00	2783	.00	67	.00	861	.00	33	.00	167	.00	601	.00	12699	.04
Total Supply	2139	.35	3501	.54	14576	.86	7486	.47	23803	.88	54625	.81	5444	.52	8447	.77	6436	.87	3432	.80	129892	.78
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2001	1.00	0	.00	58	.17	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2059	.98
From 3	0	.00	8148	1.00	0	.00	24	.00	995	.36	0	.00	0	.00	0	.00	0	.00	0	.00	9167	.93
From 4	0	.00	0	.00	4601	.46	0	.00	9905	.41	34	.09	0	.00	0	.00	0	.00	0	.00	14540	.42
From 5	0	.00	0	.00	4501	.40	0	.00	0	.00	0	.00	1528	.38	0	.00	0	.00	0	.00	6029	.39
From 6	0	.00	0	.00	0	.00	19466	.61	0	.00	0	.00	9192	.74	984	.09	4319	.65	0	.00	33961	.63
From 7	0	.00	0	.00	0	.00	0	.00	7252	.56	160	.10	0	.00	360	.35	0	.00	0	.00	7772	.54
From 8	0	.00	0	.00	0	.00	0	.00	1363	1.00	1084	.31	1040	.45	0	.00	0	.00	324	.49	3811	.61
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.67	0	.00	1517	.55
Total PL In	2001	1.00	8148	1.00	9160	.43	19490	.61	19515	.50	1278	.28	11760	.67	1603	.13	5577	.66	324	.49		
PIPELINE FLOW OUT																						
To 1	0	.00	2001	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2001	1.00
To 2	0	.00	0	.00	8148	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8148	1.00
To 3	0	.00	58	.17	0	.00	4601	.46	4501	.40	0	.00	0	.00	0	.00	0	.00	0	.00	9160	.43
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19466	.61	0	.00	0	.00	0	.00	0	.00	19490	.61
To 5	0	.00	0	.00	995	.36	9905	.41	0	.00	0	.00	7252	.56	1363	1.00	0	.00	0	.00	19515	.50
To 6	0	.00	0	.00	0	.00	34	.09	0	.00	0	.00	160	.10	1084	.31	0	.00	0	.00	1278	.28
To 7	0	.00	0	.00	0	.00	0	.00	1528	.38	9192	.74	0	.00	1040	.45	0	.00	0	.00	11760	.67
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.09	360	.35	0	.00	0	.00	259	.00	1603	.13
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	4319	.65	0	.00	0	.00	0	.00	1258	.67	5577	.66
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.49	0	.00	0	.00	324	.49
Total PL Out	0	.00	2059	.98	9167	.93	14540	.42	6029	.39	33961	.63	7772	.54	3811	.61	0	.00	1517	.55		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 1995 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	546	1.00	1557	1.00	1239	1.00	1003	1.00	4308	1.00	1146	1.00	882	1.00	554	1.00	1548	1.00	226	1.00	13009	1.00
Commercial	273	1.00	904	1.00	686	1.00	768	1.00	2209	1.00	817	1.00	573	1.00	360	1.00	857	1.00	205	1.00	7652	1.00
Industrial Firm	144	1.00	290	1.00	458	1.00	713	1.00	684	1.00	7174	1.00	194	1.00	128	1.00	1226	1.00	80	1.00	11089	1.00
Elec Util Firm	96	1.00	48	1.00	45	1.00	231	1.00	149	1.00	3173	1.00	16	1.00	16	1.00	109	1.00	0	.00	3883	1.00
Ind Interrupt	101	1.00	367	1.00	902	1.00	1822	1.00	2718	1.00	1713	1.00	670	1.00	349	1.00	740	1.00	372	1.00	9754	1.00
Elec Interrupt	208	1.00	806	1.00	114	1.00	404	1.00	178	1.00	859	1.00	90	1.00	104	1.00	1463	1.00	45	1.00	4271	1.00
Fuel	52	1.00	156	1.00	210	1.00	387	1.00	1985	1.00	3769	1.00	208	1.00	511	1.00	307	1.00	36	1.00	7621	1.00
Total Demand	1419	1.00	4127	1.00	3654	1.00	5328	1.00	12231	1.00	18651	1.00	2633	1.00	2021	1.00	6250	1.00	964	1.00	57282	1.00
SUPPLIES																						
Production	0	.00	65	1.00	1201	1.00	2962	1.00	1159	1.00	39272	1.00	1833	1.00	7153	.91	1243	1.00	10	1.00	54896	.99
Imports	32	1.00	1341	1.00	0	.00	0	.00	2567	.06	370	.00	0	.00	1780	.00	0	.00	3026	.49	9116	.33
Base Load LNG	315	.00	0	.00	0	.00	0	.00	0	.00	600	.00	0	.00	0	.00	0	.00	0	.00	915	.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	.09	1405	1.00	1200	1.00	2962	1.00	3725	.35	40242	.98	1832	1.00	8933	.73	1242	1.00	3035	.49	64927	.88
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.59	0	.00	183	.27	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.57
From 3	0	.00	8541	.49	0	.00	24	.00	995	.54	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.49
From 4	0	.00	0	.00	4601	.95	0	.00	10017	.84	34	.15	0	.00	0	.00	0	.00	0	.00	14652	.87
From 5	0	.00	0	.00	4661	.59	0	.00	0	.00	0	.00	1841	.57	0	.00	0	.00	0	.00	6502	.58
From 6	0	.00	0	.00	0	.00	19566	.77	0	.00	0	.00	9192	.33	984	.13	5065	.68	0	.00	34807	.62
From 7	0	.00	0	.00	0	.00	0	.00	7273	.57	160	.15	0	.00	360	.52	0	.00	0	.00	7793	.55
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	1.00	4824	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.68	0	.00	1517	.56
Total PL In	2344	.59	8541	.49	9445	.76	19590	.77	19961	.74	1278	.87	12073	.42	1603	.20	7023	.71	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.59	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.59
To 2	0	.00	0	.00	8541	.49	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.49
To 3	0	.00	183	.27	0	.00	4601	.95	4661	.59	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.76
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.77	0	.00	0	.00	0	.00	0	.00	19590	.77
To 5	0	.00	0	.00	995	.54	10017	.84	0	.00	0	.00	7273	.57	1676	1.00	0	.00	0	.00	19961	.74
To 6	0	.00	0	.00	0	.00	34	.15	0	.00	0	.00	160	.15	1084	1.00	0	.00	0	.00	1278	.87
To 7	0	.00	0	.00	0	.00	0	.00	1841	.57	9192	.33	0	.00	1040	1.00	0	.00	0	.00	12073	.42
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.13	360	.52	0	.00	0	.00	259	.00	1603	.20
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.68	0	.00	700	1.00	0	.00	1258	.68	7023	.71
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2527	.57	9560	.49	14652	.87	6502	.58	34807	.62	7793	.55	4824	1.00	0	.00	1517	.56		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 1995 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1096	1.00	3165	1.00	2596	1.00	2256	1.00	9451	1.00	2623	1.00	2033	1.00	1074	1.00	2611	1.00	416	1.00	27321	1.00
Commercial	485	1.00	1613	1.00	1307	1.00	1418	1.00	4716	1.00	1459	1.00	1087	1.00	685	1.00	1114	1.00	342	1.00	14227	1.00
Industrial Firm	183	1.00	406	1.00	668	1.00	971	1.00	1187	1.00	7236	1.00	288	1.00	160	1.00	1310	1.00	98	1.00	12506	1.00
Elec Util Firm	173	1.00	86	1.00	83	1.00	277	1.00	278	1.00	2141	1.00	22	1.00	16	1.00	80	1.00	0	.00	3156	1.00
Ind Interrupt	55	1.00	268	1.00	820	1.00	1483	1.00	2749	1.00	1619	1.00	663	1.00	351	1.00	710	1.00	347	1.00	9063	1.00
Elec Interrupt	2	1.00	106	1.00	15	1.00	170	1.00	152	1.00	517	1.00	34	1.00	242	1.00	940	1.00	0	.00	2177	1.00
Fuel	84	1.00	226	1.00	349	1.00	470	1.00	2471	1.00	3891	1.00	352	1.00	638	1.00	319	1.00	48	1.00	8848	1.00
Total Demand	2077	1.00	5869	1.00	5838	1.00	7045	1.00	21003	1.00	19486	1.00	4479	1.00	3166	1.00	7083	1.00	1250	1.00	77301	1.00
SUPPLIES																						
Production	0	.00	63	1.00	1171	1.00	2888	1.00	1130	1.00	38291	1.00	1787	1.00	6974	1.00	1212	1.00	9	1.00	53524	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2567	1.00	370	1.00	0	.00	1780	.26	0	.00	3026	.80	9116	.79
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	537	1.00	5583	.90	1300	.91	7185	1.00	4445	.00	1789	.71	683	.00	1457	.32	178	.00	23157	.68
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1941	1.00	6753	.92	4188	.97	10881	1.00	43705	.90	3575	.86	9437	.79	2668	.63	3213	.75	86712	.89
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.74	0	.00	183	.27	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.70
From 3	0	.00	8541	.67	0	.00	24	.00	995	.54	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.65
From 4	0	.00	0	.00	4601	.67	0	.00	10017	.82	34	.15	0	.00	0	.00	0	.00	0	.00	14652	.77
From 5	0	.00	0	.00	4661	.59	0	.00	0	.00	0	.00	1841	.57	0	.00	0	.00	0	.00	6502	.58
From 6	0	.00	0	.00	0	.00	19566	.73	0	.00	0	.00	9192	.33	984	.13	5065	.68	0	.00	34807	.60
From 7	0	.00	0	.00	0	.00	0	.00	7273	.48	160	.15	0	.00	360	.52	0	.00	0	.00	7793	.48
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	.26	4824	.95
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	.74	8541	.67	9445	.62	19590	.73	19961	.70	1278	.87	12073	.42	1603	.20	7023	.77	324	.26		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.74	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.74
To 2	0	.00	0	.00	8541	.67	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.67
To 3	0	.00	183	.27	0	.00	4601	.67	4661	.59	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.62
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.73	0	.00	0	.00	0	.00	0	.00	19590	.73
To 5	0	.00	0	.00	995	.54	10017	.82	0	.00	0	.00	7273	.48	1676	1.00	0	.00	0	.00	19961	.70
To 6	0	.00	0	.00	0	.00	34	.15	0	.00	0	.00	160	.15	1084	1.00	0	.00	0	.00	1278	.87
To 7	0	.00	0	.00	0	.00	0	.00	1841	.57	9192	.33	0	.00	1040	1.00	0	.00	0	.00	12073	.42
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.13	360	.52	0	.00	0	.00	259	.00	1603	.20
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.68	0	.00	700	1.00	0	.00	1258	1.00	7023	.77
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.26	0	.00	0	.00	324	.26
Total PL Out	0	.00	2527	.70	9560	.65	14652	.77	6502	.58	34807	.60	7793	.48	4824	.95	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 1995 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1808	1.00	5507	1.00	5141	1.00	5234	1.00	18807	1.00	6531	1.00	3965	1.00	2203	1.00	6056	1.00	1240	1.00	56492	1.00
Commercial	897	1.00	2581	1.00	2287	1.00	2808	1.00	8489	1.00	2830	1.00	1794	1.00	1357	1.00	1816	1.00	838	1.00	25698	1.00
Industrial Firm	223	1.00	502	1.00	906	1.00	1452	1.00	1828	1.00	8671	1.00	417	1.00	200	1.00	1464	1.00	134	1.00	15796	1.00
Elec Util Firm	0	.00	3	1.00	5	1.00	184	1.00	13	1.00	2141	1.00	8	1.00	16	1.00	80	1.00	0	.00	2450	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	136	1.00	371	1.00	675	1.00	715	1.00	4190	1.00	4765	1.00	560	1.00	1109	1.00	569	1.00	74	1.00	13165	1.00
Total Demand	3064	1.00	8964	1.00	9014	1.00	10393	1.00	33328	1.00	24938	1.00	6743	1.00	4885	1.00	9985	1.00	2285	1.00	113603	1.00
SUPPLIES																						
Production	0	.00	63	1.00	1171	1.00	2888	1.00	1130	1.00	36720	1.00	1759	1.00	6974	1.00	1212	1.00	9	1.00	51925	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2567	1.00	370	1.00	0	.00	1780	1.00	0	.00	3026	1.00	9116	1.00
Base Load LNG	360	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	1060	1.00
Storage	0	.00	1008	1.00	11269	1.00	3395	1.00	17792	1.00	10058	.95	2713	1.00	1870	.00	5100	1.00	450	.00	53655	.95
Peak Shaving	1827	.24	1680	.17	2005	.00	2675	.00	2783	.00	67	.00	861	.00	33	.00	167	.00	601	.00	12699	.06
Total Supply	2219	.37	4092	.66	14444	.86	8958	.70	24271	.89	47914	.99	5333	.84	10657	.82	6478	.97	4086	.74	128455	.88
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.96	0	.00	183	.18	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.90
From 3	0	.00	8541	1.00	0	.00	24	.00	995	.36	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.93
From 4	0	.00	0	.00	4601	.78	0	.00	10017	.51	34	.09	0	.00	0	.00	0	.00	0	.00	14652	.59
From 5	0	.00	0	.00	4661	.40	0	.00	0	.00	0	.00	1841	.38	0	.00	0	.00	0	.00	6502	.39
From 6	0	.00	0	.00	0	.00	19566	.65	0	.00	0	.00	9192	.86	984	.09	5065	.46	0	.00	34807	.67
From 7	0	.00	0	.00	0	.00	0	.00	7273	1.00	160	.10	0	.00	360	.35	0	.00	0	.00	7793	.95
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	.71	1040	1.00	0	.00	700	.77	324	.18	4824	.85
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.64	0	.00	1517	.53
Total PL In	2344	.96	8541	1.00	9445	.58	19590	.65	19961	.72	1278	.62	12073	.80	1603	.13	7023	.52	324	.18		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.96	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.96
To 2	0	.00	0	.00	8541	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	1.00
To 3	0	.00	183	.18	0	.00	4601	.78	4661	.40	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.58
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.65	0	.00	0	.00	0	.00	0	.00	19590	.65
To 5	0	.00	0	.00	995	.36	10017	.51	0	.00	0	.00	7273	1.00	1676	1.00	0	.00	0	.00	19961	.72
To 6	0	.00	0	.00	0	.00	34	.09	0	.00	0	.00	160	.10	1084	.71	0	.00	0	.00	1278	.62
To 7	0	.00	0	.00	0	.00	0	.00	1841	.38	9192	.86	0	.00	1040	1.00	0	.00	0	.00	12073	.80
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.09	360	.35	0	.00	0	.00	259	.00	1603	.13
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.46	0	.00	700	.77	0	.00	1258	.64	7023	.52
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.18	0	.00	0	.00	324	.18
Total PL Out	0	.00	2527	.90	9560	.93	14652	.59	6502	.39	34807	.67	7793	.95	4824	.85	0	.00	1517	.53		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 2000 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	588	1.00	1556	1.00	1209	1.00	969	1.00	4280	1.00	1110	1.00	877	1.00	566	1.00	1566	1.00	221	1.00	12940	1.00
Commercial	293	1.00	896	1.00	694	1.00	846	1.00	2263	1.00	827	1.00	580	1.00	363	1.00	907	1.00	195	1.00	7863	1.00
Industrial Firm	173	1.00	341	1.00	543	1.00	729	1.00	678	1.00	7235	1.00	197	1.00	160	1.00	1317	1.00	104	1.00	11474	1.00
Elec Util Firm	106	1.00	69	1.00	136	1.00	654	1.00	122	1.00	3777	1.00	59	1.00	351	1.00	168	1.00	0	.00	5442	1.00
Ind Interrupt	88	1.00	314	1.00	779	1.00	1753	1.00	2551	1.00	1710	1.00	670	1.00	380	1.00	835	1.00	372	1.00	9453	1.00
Elec Interrupt	245	1.00	689	1.00	162	1.00	410	1.00	271	1.00	987	1.00	117	1.00	104	1.00	1798	1.00	56	1.00	4838	1.00
Fuel	58	1.00	154	1.00	224	1.00	455	1.00	2040	1.00	3855	1.00	196	1.00	646	1.00	371	1.00	38	1.00	8035	1.00
Total Demand	1551	1.00	4018	1.00	3746	1.00	5815	1.00	12206	1.00	19500	1.00	2694	1.00	2569	1.00	6961	1.00	985	1.00	60049	1.00
SUPPLIES																						
Production	0	.00	74	1.00	1361	1.00	3891	1.00	1415	1.00	37689	1.00	1635	1.00	8298	.87	1757	1.00	13	1.00	56131	.98
Imports	32	1.00	1341	1.00	0	.00	0	.00	2567	.95	370	.00	0	.00	2478	.00	0	.00	3157	.39	9945	.51
Base Load LNG	315	.00	0	.00	0	.00	0	.00	0	.00	600	.00	0	.00	0	.00	0	.00	0	.00	915	.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	.09	1414	1.00	1360	1.00	3891	1.00	3981	.97	38658	.97	1634	1.00	10776	.67	1756	1.00	3170	.39	66991	.90
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.65	0	.00	183	.18	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.61
From 3	0	.00	8541	.49	0	.00	24	.00	995	.36	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.47
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.67	34	.09	0	.00	0	.00	0	.00	0	.00	14652	.77
From 5	0	.00	0	.00	4661	.49	0	.00	0	.00	0	.00	1841	.38	0	.00	0	.00	0	.00	6502	.46
From 6	0	.00	0	.00	0	.00	19566	.68	0	.00	0	.00	9192	.22	984	.09	5065	.77	0	.00	34807	.55
From 7	0	.00	0	.00	0	.00	0	.00	7273	.35	160	.10	0	.00	360	.35	0	.00	0	.00	7793	.35
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	1.00	4824	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.46	0	.00	1517	.38
Total PL In	2344	.65	8541	.49	9445	.73	19590	.68	19961	.57	1278	.86	12073	.31	1603	.13	7023	.74	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.65	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.65
To 2	0	.00	0	.00	8541	.49	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.49
To 3	0	.00	183	.18	0	.00	4601	1.00	4661	.49	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.73
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.68	0	.00	0	.00	0	.00	0	.00	19590	.68
To 5	0	.00	0	.00	995	.36	10017	.67	0	.00	0	.00	7273	.35	1676	1.00	0	.00	0	.00	19961	.57
To 6	0	.00	0	.00	0	.00	34	.09	0	.00	0	.00	160	.10	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.38	9192	.22	0	.00	1040	1.00	0	.00	0	.00	12073	.31
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.09	360	.35	0	.00	0	.00	259	.00	1603	.13
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.77	0	.00	700	1.00	0	.00	1258	.46	7023	.74
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2527	.61	9560	.47	14652	.77	6502	.46	34807	.55	7793	.35	4824	1.00	0	.00	1517	.38		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 2000 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1181	1.00	3163	1.00	2533	1.00	2178	1.00	9389	1.00	2539	1.00	2022	1.00	1097	1.00	2640	1.00	408	1.00	27149	1.00
Commercial	520	1.00	1600	1.00	1322	1.00	1562	1.00	4833	1.00	1476	1.00	1101	1.00	691	1.00	1179	1.00	325	1.00	14606	1.00
Industrial Firm	216	1.00	455	1.00	750	1.00	985	1.00	1156	1.00	7310	1.00	291	1.00	198	1.00	1399	1.00	127	1.00	12885	1.00
Elec Util Firm	193	1.00	122	1.00	367	1.00	1112	1.00	306	1.00	2695	1.00	151	1.00	573	1.00	171	1.00	0	.00	5688	1.00
Ind Interrupt	47	1.00	229	1.00	708	1.00	1427	1.00	2579	1.00	1617	1.00	663	1.00	383	1.00	802	1.00	347	1.00	8802	1.00
Elec Interrupt	3	1.00	91	1.00	21	1.00	172	1.00	231	1.00	594	1.00	44	1.00	242	1.00	1155	1.00	0	.00	2552	1.00
Fuel	92	1.00	230	1.00	372	1.00	560	1.00	2532	1.00	3946	1.00	340	1.00	806	1.00	381	1.00	48	1.00	9307	1.00
Total Demand	2252	1.00	5887	1.00	6072	1.00	7996	1.00	21025	1.00	20176	1.00	4612	1.00	3989	1.00	7725	1.00	1254	1.00	80992	1.00
SUPPLIES																						
Production	0	.00	72	1.00	1327	1.00	3794	1.00	1379	1.00	36746	1.00	1594	1.00	8091	1.00	1713	1.00	13	1.00	54727	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2567	1.00	370	1.00	0	.00	2478	.13	0	.00	3157	.78	9945	.71
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	537	1.00	5583	1.00	1300	1.00	7185	1.00	4445	.09	1789	1.00	683	.00	1457	1.00	178	.00	23157	.79
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1949	1.00	6909	1.00	5094	1.00	11131	1.00	42161	.90	3382	1.00	11251	.75	3169	1.00	3348	.74	88744	.91
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.81	0	.00	183	.09	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.76
From 3	0	.00	8541	.69	0	.00	24	.00	995	.18	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.63
From 4	0	.00	0	.00	4601	.92	0	.00	10017	.20	34	.06	0	.00	0	.00	0	.00	0	.00	14652	.43
From 5	0	.00	0	.00	4661	.20	0	.00	0	.00	0	.00	1841	.19	0	.00	0	.00	0	.00	6502	.20
From 6	0	.00	0	.00	0	.00	19566	.47	0	.00	0	.00	9192	.78	984	.04	5065	.51	0	.00	34807	.55
From 7	0	.00	0	.00	0	.00	0	.00	7273	1.00	160	.05	0	.00	360	.17	0	.00	0	.00	7793	.94
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	.09	4824	.94
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	.81	8541	.69	9445	.55	19590	.47	19961	.56	1278	.86	12073	.71	1603	.06	7023	.65	324	.09		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.81	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.81
To 2	0	.00	0	.00	8541	.69	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.69
To 3	0	.00	183	.09	0	.00	4601	.92	4661	.20	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.55
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.47	0	.00	0	.00	0	.00	0	.00	19590	.47
To 5	0	.00	0	.00	995	.18	10017	.20	0	.00	0	.00	7273	1.00	1676	1.00	0	.00	0	.00	19961	.56
To 6	0	.00	0	.00	0	.00	34	.06	0	.00	0	.00	160	.05	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.19	9192	.78	0	.00	1040	1.00	0	.00	0	.00	12073	.71
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.04	360	.17	0	.00	0	.00	259	.00	1603	.06
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.51	0	.00	700	1.00	0	.00	1258	1.00	7023	.65
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.09	0	.00	0	.00	324	.09
Total PL Out	0	.00	2527	.76	9560	.63	14652	.43	6502	.20	34807	.55	7793	.94	4824	.94	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 2000 HIGH REFERENCE CASE

	REGION 1 Cap MMcfd	REGION 1 Util Rate	REGION 2 Cap MMcfd	REGION 2 Util Rate	REGION 3 Cap MMcfd	REGION 3 Util Rate	REGION 4 Cap MMcfd	REGION 4 Util Rate	REGION 5 Cap MMcfd	REGION 5 Util Rate	REGION 6 Cap MMcfd	REGION 6 Util Rate	REGION 7 Cap MMcfd	REGION 7 Util Rate	REGION 8 Cap MMcfd	REGION 8 Util Rate	REGION 9 Cap MMcfd	REGION 9 Util Rate	REGION 10 Cap MMcfd	REGION 10 Util Rate	TOTAL Cap MMcfd	TOTAL Util Rate
DEMAND																						
Residential	1807	1.00	5534	1.00	5192	1.00	5358	1.00	19060	1.00	6703	1.00	4004	1.00	2259	1.00	6178	1.00	1314	1.00	57409	1.00
Commercial	963	1.00	2559	1.00	2313	1.00	3093	1.00	8699	1.00	2863	1.00	1816	1.00	1367	1.00	1921	1.00	796	1.00	26389	1.00
Industrial Firm	253	.99	536	1.00	955	1.00	1448	1.00	1755	1.00	8742	1.00	420	1.00	242	1.00	1573	1.00	162	1.00	16084	1.00
Elec Util Firm	0	.00	3	.67	11	1.00	186	1.00	21	1.00	2464	1.00	8	1.00	16	1.00	100	1.00	0	.00	2809	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	149	1.00	375	1.00	710	1.00	840	1.00	4286	1.00	4833	1.00	541	1.00	1380	1.00	686	1.00	75	1.00	13874	1.00
Total Demand	3171	1.00	9007	1.00	9180	1.00	10925	1.00	33821	1.00	25604	1.00	6789	1.00	5263	1.00	10457	1.00	2345	1.00	116567	1.00
SUPPLIES																						
Production	0	.00	72	1.00	1327	1.00	3794	1.00	1379	1.00	35239	1.00	1569	1.00	8091	1.00	1713	1.00	13	1.00	53195	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2567	1.00	370	1.00	0	.00	2478	.77	0	.00	3157	1.00	9945	.94
Base Load LNG	360	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	1060	1.00
Storage	0	.00	1008	1.00	11269	1.00	3395	1.00	17792	1.00	10058	1.00	2713	1.00	1870	.00	5100	1.00	450	.24	53655	.96
Peak Shaving	1827	.24	1680	.24	2005	.17	2675	.00	2783	.12	67	.00	861	.00	33	.00	167	.00	601	.00	12699	.12
Total Supply	2219	.37	4100	.69	14600	.89	9864	.73	24521	.90	46433	1.00	5143	.83	12471	.80	6979	.98	4221	.78	130554	.89
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	1.00	0	.00	183	.09	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.93
From 3	0	.00	8541	1.00	0	.00	24	.00	995	.18	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.91
From 4	0	.00	0	.00	4601	.87	0	.00	10017	.64	34	.06	0	.00	0	.00	0	.00	0	.00	14652	.71
From 5	0	.00	0	.00	4661	.20	0	.00	0	.00	0	.00	1841	.19	0	.00	0	.00	0	.00	6502	.20
From 6	0	.00	0	.00	0	.00	19566	.72	0	.00	0	.00	9192	.65	984	.04	5065	.33	0	.00	34807	.63
From 7	0	.00	0	.00	0	.00	0	.00	7273	.66	160	.05	0	.00	360	.17	0	.00	0	.00	7793	.62
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	1.00	4824	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	1.00	8541	1.00	9445	.53	19590	.72	19961	.65	1278	.86	12073	.61	1603	.06	7023	.52	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	1.00
To 2	0	.00	0	.00	8541	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	1.00
To 3	0	.00	183	.09	0	.00	4601	.87	4661	.20	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.53
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.72	0	.00	0	.00	0	.00	0	.00	19590	.72
To 5	0	.00	0	.00	995	.18	10017	.64	0	.00	0	.00	7273	.66	1676	1.00	0	.00	0	.00	19961	.65
To 6	0	.00	0	.00	0	.00	34	.06	0	.00	0	.00	160	.05	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.19	9192	.65	0	.00	1040	1.00	0	.00	0	.00	12073	.61
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.04	360	.17	0	.00	0	.00	259	.00	1603	.06
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.33	0	.00	700	1.00	0	.00	1258	1.00	7023	.52
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2527	.93	9560	.91	14652	.71	6502	.20	34807	.63	7793	.62	4824	1.00	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 2005 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	642	1.00	1581	1.00	1196	1.00	937	1.00	4280	1.00	1088	1.00	872	1.00	589	1.00	1592	1.00	217	1.00	12993	1.00
Commercial	337	1.00	999	1.00	776	1.00	949	1.00	2476	1.00	938	1.00	634	1.00	403	1.00	1043	1.00	214	1.00	8767	1.00
Industrial Firm	245	1.00	396	1.00	628	1.00	870	1.00	708	1.00	7552	1.00	205	1.00	176	1.00	1471	1.00	136	1.00	12384	1.00
Elec Util Firm	157	1.00	144	1.00	266	1.00	803	1.00	290	1.00	4139	1.00	93	1.00	487	1.00	282	1.00	43	1.00	6703	1.00
Ind Interrupt	122	1.00	383	1.00	939	1.00	2093	1.00	2652	1.00	1777	1.00	705	1.00	420	1.00	811	1.00	415	1.00	10317	1.00
Elec Interrupt	295	1.00	944	1.00	160	1.00	418	1.00	274	1.00	968	1.00	114	1.00	109	1.00	2107	1.00	72	1.00	5460	1.00
Fuel	70	1.00	177	1.00	250	1.00	483	1.00	2093	1.00	3558	1.00	187	1.00	747	1.00	454	1.00	44	1.00	8061	1.00
Total Demand	1867	1.00	4623	1.00	4214	1.00	6552	1.00	12772	1.00	20019	1.00	2810	1.00	2930	1.00	7759	1.00	1139	1.00	64689	1.00
SUPPLIES																						
Production	0	.00	81	1.00	1492	1.00	3801	1.00	1444	1.00	38914	1.00	1469	1.00	9215	.83	2522	1.00	21	1.00	58957	.97
Imports	32	1.00	1341	1.00	0	.00	0	.00	2682	1.00	370	1.00	0	.00	2478	.00	0	.00	3327	.62	10230	.63
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	.83	0	.00	0	.00	0	.00	0	.00	915	.89
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1421	1.00	1491	1.00	3801	1.00	4125	1.00	39884	1.00	1468	1.00	11692	.65	2521	1.00	3347	.62	70102	.92
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.65	0	.00	183	.09	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.61
From 3	0	.00	8541	.55	0	.00	24	.00	995	.18	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.51
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.32	34	.06	0	.00	0	.00	0	.00	0	.00	14652	.54
From 5	0	.00	0	.00	4661	.65	0	.00	0	.00	0	.00	1841	.19	0	.00	0	.00	0	.00	6502	.52
From 6	0	.00	0	.00	0	.00	19566	.54	0	.00	0	.00	9192	.75	984	.04	5065	.65	0	.00	34807	.60
From 7	0	.00	0	.00	0	.00	0	.00	7273	.95	160	.05	0	.00	360	.17	0	.00	0	.00	7793	.90
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	1.00	4824	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	.65	8541	.55	9445	.81	19590	.54	19961	.60	1278	.86	12073	.69	1603	.06	7023	.75	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.65	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.65
To 2	0	.00	0	.00	8541	.55	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.55
To 3	0	.00	183	.09	0	.00	4601	1.00	4661	.65	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.81
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.54	0	.00	0	.00	0	.00	0	.00	19590	.54
To 5	0	.00	0	.00	995	.18	10017	.32	0	.00	0	.00	7273	.95	1676	1.00	0	.00	0	.00	19961	.60
To 6	0	.00	0	.00	0	.00	34	.06	0	.00	0	.00	160	.05	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.19	9192	.75	0	.00	1040	1.00	0	.00	0	.00	12073	.69
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.04	360	.17	0	.00	0	.00	259	.00	1603	.06
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.65	0	.00	700	1.00	0	.00	1258	1.00	7023	.75
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2527	.61	9560	.51	14652	.54	6502	.52	34807	.60	7793	.90	4824	1.00	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 2005 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1290	1.00	3214	1.00	2506	1.00	2106	1.00	9390	1.00	2489	1.00	2012	1.00	1141	1.00	2684	1.00	399	1.00	27231	1.00
Commercial	597	1.00	1782	1.00	1479	1.00	1752	1.00	5287	1.00	1675	1.00	1203	1.00	766	1.00	1355	1.00	358	1.00	16253	1.00
Industrial Firm	305	1.00	533	1.00	873	1.00	1175	1.00	1205	1.00	7637	1.00	303	1.00	218	1.00	1585	1.00	165	1.00	13999	1.00
Elec Util Firm	251	1.00	210	1.00	740	1.00	1938	1.00	803	1.00	3428	1.00	248	1.00	865	1.00	352	1.00	114	1.00	8947	1.00
Ind Interrupt	66	1.00	280	1.00	853	1.00	1704	1.00	2681	1.00	1680	1.00	697	1.00	423	1.00	779	1.00	386	1.00	9549	1.00
Elec Interrupt	3	1.00	124	.99	20	1.00	175	1.00	233	1.00	583	1.00	43	1.00	254	1.00	1353	1.00	0	.00	2790	1.00
Fuel	106	1.00	247	1.00	416	1.00	612	1.00	2609	1.00	3649	1.00	332	1.00	930	1.00	462	1.00	57	1.00	9417	1.00
Total Demand	2618	1.00	6390	1.00	6887	1.00	9462	1.00	22207	1.00	21139	1.00	4837	1.00	4597	1.00	8569	1.00	1477	1.00	88188	1.00
SUPPLIES																						
Production	0	.00	79	1.00	1454	1.00	3706	1.00	1408	1.00	37941	1.00	1432	1.00	8985	1.00	2459	1.00	20	1.00	57483	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2682	1.00	370	1.00	0	.00	2478	.12	0	.00	3327	.83	10230	.73
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	537	1.00	5583	1.00	1300	1.00	7185	1.00	4445	1.00	1789	1.00	683	.00	1457	1.00	178	.00	23157	.96
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1956	1.00	7037	1.00	5006	1.00	11274	1.00	43356	1.00	3221	1.00	12145	.76	3915	1.00	3525	.79	91785	.96
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.97	0	.00	183	.09	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.91
From 3	0	.00	8541	.79	0	.00	24	.00	995	.18	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.72
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.42	34	.06	0	.00	0	.00	0	.00	0	.00	14652	.60
From 5	0	.00	0	.00	4661	.46	0	.00	0	.00	0	.00	1841	.19	0	.00	0	.00	0	.00	6502	.38
From 6	0	.00	0	.00	0	.00	19566	.68	0	.00	0	.00	9192	.82	984	.04	5065	.51	0	.00	34807	.67
From 7	0	.00	0	.00	0	.00	0	.00	7273	1.00	160	.05	0	.00	360	.17	0	.00	0	.00	7793	.94
From 8	0	.00	0	.00	0	.00	0	.00	1776	1.00	1149	1.00	1102	1.00	0	.00	742	1.00	324	.09	5093	.94
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1333	1.00	0	.00	1592	.84
Total PL In	2344	.97	8541	.79	9445	.71	19590	.68	20061	.67	1343	.86	12135	.74	1603	.06	7140	.65	324	.09		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.97	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.97
To 2	0	.00	0	.00	8541	.79	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.79
To 3	0	.00	183	.09	0	.00	4601	1.00	4661	.46	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.71
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.68	0	.00	0	.00	0	.00	0	.00	19590	.68
To 5	0	.00	0	.00	995	.18	10017	.42	0	.00	0	.00	7273	1.00	1776	1.00	0	.00	0	.00	20061	.67
To 6	0	.00	0	.00	0	.00	34	.06	0	.00	0	.00	160	.05	1149	1.00	0	.00	0	.00	1343	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.19	9192	.82	0	.00	1102	1.00	0	.00	0	.00	12135	.74
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.04	360	.17	0	.00	0	.00	259	.00	1603	.06
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.51	0	.00	742	1.00	0	.00	1333	1.00	7140	.65
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.09	0	.00	0	.00	324	.09
Total PL Out	0	.00	2527	.91	9560	.72	14652	.60	6502	.38	34807	.67	7793	.94	5093	.94	0	.00	1592	.84		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 2005 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1805	1.00	5625	1.00	5263	1.00	5434	1.00	19437	1.00	6820	1.00	4044	1.00	2305	1.00	6254	1.00	1369	1.00	58356	1.00
Commercial	1105	1.00	2852	1.00	2589	1.00	3469	1.00	9516	1.00	3249	1.00	1984	1.00	1516	1.00	2209	1.00	876	1.00	29364	1.00
Industrial Firm	355	1.00	633	1.00	1120	1.00	1727	1.00	1830	1.00	9123	1.00	437	1.00	266	1.00	1753	1.00	203	1.00	17448	1.00
Elec Util Firm	0	.00	3	1.00	8	1.00	192	1.00	21	1.00	2412	1.00	8	1.00	16	1.00	118	1.00	0	.00	2777	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	171	1.00	405	1.00	797	1.00	918	1.00	4410	1.00	4466	1.00	528	1.00	1584	1.00	830	1.00	88	1.00	14195	1.00
Total Demand	3436	1.00	9517	1.00	9776	1.00	11739	1.00	35213	1.00	26069	1.00	7001	1.00	5687	1.00	11164	1.00	2536	1.00	122141	1.00
SUPPLIES																						
Production	0	.00	79	1.00	1454	1.00	3706	1.00	1408	1.00	36385	1.00	1410	1.00	8985	1.00	2459	1.00	20	1.00	55904	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2682	1.00	370	1.00	0	.00	2478	1.00	0	.00	3327	1.00	10230	1.00
Base Load LNG	360	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	1060	1.00
Storage	0	.00	1008	1.00	11269	1.00	3395	1.00	17792	1.00	10058	1.00	2713	1.00	1870	.16	5100	1.00	450	1.00	53655	.97
Peak Shaving	1827	.24	1680	.24	2005	.24	2675	.24	2783	.24	67	.24	861	.24	33	.00	167	.23	601	.02	12699	.23
Total Supply	2219	.37	4107	.69	14728	.90	9776	.79	24664	.91	47579	1.00	4984	.87	13365	.88	7725	.98	4398	.87	133548	.91
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2611	1.00	0	.00	183	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2794	.93
From 3	0	.00	9302	1.00	0	.00	24	.00	995	.00	0	.00	0	.00	0	.00	0	.00	0	.00	10321	.90
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.62	34	.00	0	.00	0	.00	0	.00	0	.00	14652	.74
From 5	0	.00	0	.00	4661	.27	0	.00	0	.00	0	.00	1841	.00	0	.00	0	.00	0	.00	6502	.20
From 6	0	.00	0	.00	0	.00	19566	.76	0	.00	0	.00	9192	.76	984	.00	5065	.21	0	.00	34807	.66
From 7	0	.00	0	.00	0	.00	0	.00	7273	.77	160	.00	0	.00	360	.00	0	.00	0	.00	7793	.72
From 8	0	.00	0	.00	0	.00	0	.00	2140	1.00	1384	1.00	1328	1.00	0	.00	894	1.00	324	1.00	6070	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1606	1.00	0	.00	1865	.86
Total PL In	2611	1.00	9302	1.00	9445	.62	19590	.76	20425	.68	1578	.88	12361	.67	1603	.00	7565	.47	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2611	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2611	1.00
To 2	0	.00	0	.00	9302	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	9302	1.00
To 3	0	.00	183	.00	0	.00	4601	1.00	4661	.27	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.62
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.76	0	.00	0	.00	0	.00	0	.00	19590	.76
To 5	0	.00	0	.00	995	.00	10017	.62	0	.00	0	.00	7273	.77	2140	1.00	0	.00	0	.00	20425	.68
To 6	0	.00	0	.00	0	.00	34	.00	0	.00	0	.00	160	.00	1384	1.00	0	.00	0	.00	1578	.88
To 7	0	.00	0	.00	0	.00	0	.00	1841	.00	9192	.76	0	.00	1328	1.00	0	.00	0	.00	12361	.67
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.00	360	.00	0	.00	0	.00	259	.00	1603	.00
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.21	0	.00	894	1.00	0	.00	1606	1.00	7565	.47
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2794	.93	10321	.90	14652	.74	6502	.20	34807	.66	7793	.72	6070	1.00	0	.00	1865	.86		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 2010 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	699	1.00	1613	1.00	1183	1.00	900	1.00	4308	1.00	1069	1.00	873	1.00	614	1.00	1618	1.00	211	1.00	13088	1.00
Commercial	358	1.00	1067	1.00	821	1.00	1004	1.00	2600	1.00	1021	1.00	667	1.00	434	1.00	1112	1.00	231	1.00	9315	1.00
Industrial Firm	298	1.00	418	1.00	665	1.00	939	1.00	726	1.00	7818	1.00	213	1.00	181	1.00	1559	1.00	160	1.00	12975	1.00
Elec Util Firm	253	1.00	266	1.00	386	1.00	1178	1.00	471	1.00	4559	1.00	141	1.00	572	1.00	463	1.00	77	1.00	8365	1.00
Ind Interrupt	136	1.00	399	1.00	971	1.00	2234	1.00	2721	.11	1838	1.00	721	1.00	434	1.00	833	1.00	436	1.00	10722	.77
Elec Interrupt	349	.15	1045	1.00	170	1.00	468	1.00	303	.00	966	1.00	120	1.00	120	1.00	2242	1.00	93	1.00	5875	.90
Fuel	81	1.00	193	1.00	270	1.00	509	1.00	2201	1.00	2927	1.00	175	1.00	888	1.00	515	1.00	49	1.00	7807	1.00
Total Demand	2173	.86	5000	1.00	4466	1.00	7233	1.00	13330	.80	20196	1.00	2908	1.00	3243	1.00	8340	1.00	1257	1.00	68149	.96
SUPPLIES																						
Production	0	.00	87	1.00	1598	1.00	3915	1.00	1552	1.00	35620	1.00	1111	1.00	11849	.79	3145	1.00	27	1.00	58902	.96
Imports	32	1.00	2117	1.00	0	.00	0	.00	2819	1.00	370	1.00	0	.00	2879	.00	0	.00	3639	.69	11856	.66
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	2203	1.00	1598	1.00	3914	1.00	4370	1.00	36589	1.00	1111	1.00	14727	.63	3145	1.00	3665	.69	71673	.91
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2611	.59	0	.00	183	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2794	.55
From 3	0	.00	9302	.47	0	.00	24	.00	995	.00	0	.00	0	.00	0	.00	0	.00	0	.00	10321	.42
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.67	34	.00	0	.00	0	.00	0	.00	0	.00	14652	.77
From 5	0	.00	0	.00	4661	.56	0	.00	0	.00	0	.00	1841	.00	0	.00	0	.00	0	.00	6502	.40
From 6	0	.00	0	.00	0	.00	19566	.75	0	.00	0	.00	9192	.05	984	.00	5065	.53	0	.00	34807	.51
From 7	0	.00	0	.00	0	.00	0	.00	7273	.00	160	.00	0	.00	360	.00	0	.00	0	.00	7793	.00
From 8	0	.00	0	.00	0	.00	0	.00	2140	1.00	1384	1.00	1328	1.00	0	.00	894	1.00	324	1.00	6070	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1606	1.00	0	.00	1865	.86
Total PL In	2611	.59	9302	.47	9445	.76	19590	.75	20425	.43	1578	.88	12361	.15	1603	.00	7565	.69	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2611	.59	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2611	.59
To 2	0	.00	0	.00	9302	.47	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	9302	.47
To 3	0	.00	183	.00	0	.00	4601	1.00	4661	.56	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.76
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.75	0	.00	0	.00	0	.00	0	.00	19590	.75
To 5	0	.00	0	.00	995	.00	10017	.67	0	.00	0	.00	7273	.00	2140	1.00	0	.00	0	.00	20425	.43
To 6	0	.00	0	.00	0	.00	34	.00	0	.00	0	.00	160	.00	1384	1.00	0	.00	0	.00	1578	.88
To 7	0	.00	0	.00	0	.00	0	.00	1841	.00	9192	.05	0	.00	1328	1.00	0	.00	0	.00	12361	.15
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.00	360	.00	0	.00	0	.00	259	.00	1603	.00
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.53	0	.00	894	1.00	0	.00	1606	1.00	7565	.69
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2794	.55	10321	.42	14652	.77	6502	.40	34807	.51	7793	.00	6070	1.00	0	.00	1865	.86		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 2010 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1403	1.00	3279	1.00	2479	1.00	2024	1.00	9450	1.00	2447	1.00	2013	1.00	1191	1.00	2728	1.00	389	1.00	27403	1.00
Commercial	635	1.00	1905	1.00	1564	1.00	1855	1.00	5552	1.00	1822	1.00	1265	1.00	826	1.00	1444	1.00	386	1.00	17254	1.00
Industrial Firm	370	1.00	561	1.00	922	1.00	1267	1.00	1237	1.00	7907	1.00	314	1.00	225	1.00	1685	1.00	193	1.00	14679	1.00
Elec Util Firm	336	1.00	349	1.00	1074	1.00	2969	1.00	1366	1.00	4375	1.00	385	1.00	1096	1.00	637	1.00	211	1.00	12796	1.00
Ind Interrupt	73	1.00	291	1.00	882	1.00	1819	1.00	2751	1.00	1738	1.00	713	1.00	437	1.00	799	1.00	406	1.00	9909	1.00
Elec Interrupt	4	1.00	137	1.00	22	1.00	197	1.00	258	1.00	582	1.00	45	1.00	279	1.00	1441	1.00	0	.00	2963	1.00
Fuel	118	1.00	261	1.00	447	1.00	659	1.00	2738	1.00	2996	1.00	319	1.00	1097	1.00	521	1.00	63	1.00	9219	1.00
Total Demand	2939	1.00	6782	1.00	7390	1.00	10789	1.00	23353	1.00	21864	1.00	5053	1.00	5149	1.00	9254	1.00	1648	1.00	94226	1.00
SUPPLIES																						
Production	0	.00	84	1.00	1558	1.00	3817	1.00	1513	1.00	34729	1.00	1084	1.00	11553	1.00	3066	1.00	26	1.00	57430	1.00
Imports	32	1.00	2117	1.00	0	.00	0	.00	2819	1.00	370	1.00	0	.00	2879	1.00	0	.00	3639	1.00	11856	1.00
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	547	1.00	5688	1.00	1405	1.00	7320	1.00	4803	1.00	1828	1.00	683	1.00	1574	1.00	178	1.00	24026	1.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	2748	1.00	7246	1.00	5222	1.00	11651	1.00	40502	1.00	2911	1.00	15114	1.00	4640	1.00	3842	1.00	94227	1.00
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2611	.99	0	.00	183	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2794	.93
From 3	0	.00	9302	.71	0	.00	24	.00	995	.00	0	.00	0	.00	0	.00	0	.00	0	.00	10321	.64
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.30	34	.00	0	.00	0	.00	0	.00	0	.00	14652	.52
From 5	0	.00	0	.00	4661	.47	0	.00	0	.00	0	.00	1841	.00	0	.00	0	.00	0	.00	6502	.33
From 6	0	.00	0	.00	0	.00	19566	.67	0	.00	0	.00	9192	.78	984	.00	5065	.12	0	.00	34807	.60
From 7	0	.00	0	.00	0	.00	0	.00	7273	1.00	160	.00	0	.00	360	.00	0	.00	0	.00	7793	.93
From 8	0	.00	0	.00	0	.00	0	.00	3592	1.00	2324	1.00	2229	1.00	0	.00	1501	1.00	324	.98	9970	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	2518	1.00	0	.00	2777	.91
Total PL In	2611	.99	9302	.71	9445	.72	19590	.67	21877	.63	2518	.92	13262	.71	1603	.00	9084	.51	324	.98		
PIPELINE FLOW OUT																						
To 1	0	.00	2611	.99	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2611	.99
To 2	0	.00	0	.00	9302	.71	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	9302	.71
To 3	0	.00	183	.00	0	.00	4601	1.00	4661	.47	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.72
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.67	0	.00	0	.00	0	.00	0	.00	19590	.67
To 5	0	.00	0	.00	995	.00	10017	.30	0	.00	0	.00	7273	1.00	3592	1.00	0	.00	0	.00	21877	.63
To 6	0	.00	0	.00	0	.00	34	.00	0	.00	0	.00	160	.00	2324	1.00	0	.00	0	.00	2518	.92
To 7	0	.00	0	.00	0	.00	0	.00	1841	.00	9192	.78	0	.00	2229	1.00	0	.00	0	.00	13262	.71
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.00	360	.00	0	.00	0	.00	259	.00	1603	.00
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.12	0	.00	1501	1.00	0	.00	2518	1.00	9084	.51
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.98	0	.00	0	.00	324	.98
Total PL Out	0	.00	2794	.93	10321	.64	14652	.52	6502	.33	34807	.60	7793	.93	9970	1.00	0	.00	2777	.91		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 2010 HIGH REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1824	1.00	5705	1.00	5331	1.00	5466	1.00	20035	1.00	6948	1.00	4146	1.00	2370	1.00	6384	1.00	1421	1.00	59628	1.00
Commercial	1175	1.00	3048	1.00	2737	1.00	3673	1.00	9994	1.00	3534	1.00	2088	1.00	1636	1.00	2354	1.00	946	1.00	31183	1.00
Industrial Firm	426	1.00	665	1.00	1178	1.00	1858	1.00	1878	1.00	9444	1.00	452	1.00	274	1.00	1857	1.00	234	1.00	18265	1.00
Elec Util Firm	0	.00	5	1.00	11	1.00	213	1.00	24	1.00	2407	1.00	8	1.00	16	1.00	124	1.00	0	.00	2807	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	191	1.00	428	1.00	855	1.00	983	1.00	4624	1.00	3666	1.00	506	1.00	1862	1.00	934	1.00	97	1.00	14145	1.00
Total Demand	3616	1.00	9850	1.00	10110	1.00	12192	1.00	36555	1.00	25999	1.00	7199	1.00	6156	1.00	11652	1.00	2697	1.00	126030	1.00
SUPPLIES																						
Production	0	.00	84	1.00	1558	1.00	3817	1.00	1513	1.00	33304	1.00	1067	1.00	11553	1.00	3066	1.00	26	1.00	55988	1.00
Imports	32	1.00	2117	1.00	0	.00	0	.00	2819	1.00	370	1.00	0	.00	2879	1.00	0	.00	3639	1.00	11856	1.00
Base Load LNG	360	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	1060	1.00
Storage	0	.00	1018	1.00	11374	1.00	3500	1.00	17927	1.00	10416	1.00	2752	1.00	1870	.91	5217	1.00	450	1.00	54524	1.00
Peak Shaving	1827	.24	1680	.24	2005	.24	2675	.18	2783	.24	67	.24	861	.24	33	.00	167	.23	601	.14	12699	.22
Total Supply	2219	.37	4899	.74	14937	.90	9992	.78	25041	.92	44857	1.00	4679	.86	16334	.99	8450	.98	4715	.89	136127	.93
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2792	1.00	0	.00	183	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2975	.94
From 3	0	.00	9302	.97	0	.00	24	.00	995	.00	0	.00	0	.00	0	.00	0	.00	0	.00	10321	.87
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	1.00	34	.00	0	.00	0	.00	0	.00	0	.00	14652	1.00
From 5	0	.00	0	.00	4661	.24	0	.00	0	.00	0	.00	1841	.00	0	.00	0	.00	0	.00	6502	.17
From 6	0	.00	0	.00	0	.00	19566	.97	0	.00	0	.00	9192	.23	984	.00	5065	.00	0	.00	34807	.61
From 7	0	.00	0	.00	0	.00	0	.00	7273	.16	160	.00	0	.00	360	.00	0	.00	0	.00	7793	.15
From 8	0	.00	0	.00	0	.00	0	.00	3592	1.00	2324	1.00	2229	1.00	0	.00	1501	1.00	324	1.00	9970	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	2518	.73	0	.00	2777	.66
Total PL In	2792	1.00	9302	.97	9445	.61	19590	.97	21877	.68	2518	.92	13262	.33	1603	.00	9084	.37	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2792	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2792	1.00
To 2	0	.00	0	.00	9302	.97	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	9302	.97
To 3	0	.00	183	.00	0	.00	4601	1.00	4661	.24	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.61
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.97	0	.00	0	.00	0	.00	0	.00	19590	.97
To 5	0	.00	0	.00	995	.00	10017	1.00	0	.00	0	.00	7273	.16	3592	1.00	0	.00	0	.00	21877	.68
To 6	0	.00	0	.00	0	.00	34	.00	0	.00	0	.00	160	.00	2324	1.00	0	.00	0	.00	2518	.92
To 7	0	.00	0	.00	0	.00	0	.00	1841	.00	9192	.23	0	.00	2229	1.00	0	.00	0	.00	13262	.33
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.00	360	.00	0	.00	0	.00	259	.00	1603	.00
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.00	0	.00	1501	1.00	0	.00	2518	.73	9084	.37
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2975	.94	10321	.87	14652	1.00	6502	.17	34807	.61	7793	.15	9970	1.00	0	.00	2777	.66		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 1991 LOW REFERENCE CASE

	REGION 1 Cap MMcfd	Util Rate	REGION 2 Cap MMcfd	Util Rate	REGION 3 Cap MMcfd	Util Rate	REGION 4 Cap MMcfd	Util Rate	REGION 5 Cap MMcfd	Util Rate	REGION 6 Cap MMcfd	Util Rate	REGION 7 Cap MMcfd	Util Rate	REGION 8 Cap MMcfd	Util Rate	REGION 9 Cap MMcfd	Util Rate	REGION 10 Cap MMcfd	Util Rate	TOTAL Cap MMcfd	Util Rate
DEMAND																						
Residential	455	1.00	1421	1.00	1153	1.00	955	1.00	4169	1.00	1161	1.00	891	1.00	546	1.00	1526	1.00	226	1.00	12502	1.00
Commercial	272	1.00	894	1.00	682	1.00	721	1.00	2184	1.00	773	1.00	580	1.00	359	1.00	906	1.00	201	1.00	7572	1.00
Industrial Firm	88	1.00	138	1.00	253	1.00	614	1.00	588	1.00	6602	1.00	168	1.00	77	1.00	896	1.00	48	1.00	9471	1.00
Elec Util Firm	24	1.00	32	1.00	24	1.00	221	1.00	141	1.00	3171	1.00	5	1.00	3	1.00	98	1.00	0	.00	3718	1.00
Ind Interrupt	106	1.00	359	1.00	990	1.00	1708	1.00	2593	1.00	1575	1.00	601	1.00	285	1.00	729	1.00	364	1.00	9309	1.00
Elec Interrupt	176	1.00	745	1.00	83	1.00	481	1.00	96	1.00	857	1.00	72	1.00	24	1.00	1303	1.00	35	1.00	3870	1.00
Fuel	44	1.00	146	1.00	206	1.00	275	1.00	457	1.00	3364	1.00	210	1.00	384	1.00	289	1.00	35	1.00	5410	1.00
Total Demand	1165	1.00	3734	1.00	3389	1.00	4975	1.00	10228	1.00	17501	1.00	2526	1.00	1677	1.00	5747	1.00	909	1.00	51855	1.00
SUPPLIES																						
Production	0	.00	72	1.00	1325	1.00	1461	1.00	1161	1.00	46290	.85	1956	1.00	5493	.72	1196	1.00	9	1.00	58963	.86
Imports	32	.00	743	.00	0	.00	0	.00	2085	.00	370	.00	0	.00	1225	.00	0	.00	2372	.60	6827	.21
Base Load LNG	240	.00	0	.00	0	.00	0	.00	0	.00	600	.00	0	.00	0	.00	0	.00	0	.00	840	.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	272	.00	814	.09	1325	1.00	1461	1.00	3246	.36	47259	.83	1956	1.00	6718	.59	1195	1.00	2381	.61	66630	.78
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2001	.58	0	.00	58	.28	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2059	.57
From 3	0	.00	8148	.59	0	.00	24	.00	995	.54	0	.00	0	.00	0	.00	0	.00	0	.00	9167	.59
From 4	0	.00	0	.00	4601	1.00	0	.00	9905	.73	34	.15	0	.00	0	.00	0	.00	0	.00	14540	.81
From 5	0	.00	0	.00	4501	.63	0	.00	0	.00	0	.00	1528	.57	0	.00	0	.00	0	.00	6029	.61
From 6	0	.00	0	.00	0	.00	19466	.79	0	.00	0	.00	9192	.33	984	.13	4319	.86	0	.00	33961	.65
From 7	0	.00	0	.00	0	.00	0	.00	7252	.51	160	.15	0	.00	360	.52	0	.00	0	.00	7772	.50
From 8	0	.00	0	.00	0	.00	0	.00	1363	1.00	1084	.35	1040	.52	0	.00	0	.00	324	1.00	3811	.68
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.68	0	.00	1517	.56
Total PL In	2001	.58	8148	.59	9160	.81	19490	.79	19515	.65	1278	.32	11760	.38	1603	.20	5577	.82	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2001	.58	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2001	.58
To 2	0	.00	0	.00	8148	.59	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8148	.59
To 3	0	.00	58	.28	0	.00	4601	1.00	4501	.63	0	.00	0	.00	0	.00	0	.00	0	.00	9160	.81
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19466	.79	0	.00	0	.00	0	.00	0	.00	19490	.79
To 5	0	.00	0	.00	995	.54	9905	.73	0	.00	0	.00	7252	.51	1363	1.00	0	.00	0	.00	19515	.65
To 6	0	.00	0	.00	0	.00	34	.15	0	.00	0	.00	160	.15	1084	.35	0	.00	0	.00	1278	.32
To 7	0	.00	0	.00	0	.00	0	.00	1528	.57	9192	.33	0	.00	1040	.52	0	.00	0	.00	11760	.38
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.13	360	.52	0	.00	0	.00	259	.00	1603	.20
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	4319	.86	0	.00	0	.00	0	.00	1258	.68	5577	.82
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2059	.57	9167	.59	14540	.81	6029	.61	33961	.65	7772	.50	3811	.68	0	.00	1517	.56		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 1991 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	913	1.00	2888	1.00	2415	1.00	2148	1.00	9146	1.00	2657	1.00	2054	1.00	1058	1.00	2573	1.00	417	1.00	26269	1.00
Commercial	483	1.00	1595	1.00	1300	1.00	1331	1.00	4663	1.00	1380	1.00	1101	1.00	683	1.00	1178	1.00	335	1.00	14049	1.00
Industrial Firm	119	1.00	225	1.00	439	1.00	847	1.00	1056	1.00	6661	1.00	250	1.00	99	1.00	924	1.00	61	1.00	10679	1.00
Elec Util Firm	0	.00	3	1.00	5	1.00	221	1.00	8	1.00	2139	1.00	5	1.00	3	1.00	73	1.00	0	.00	2456	1.00
Ind Interrupt	58	1.00	262	1.00	899	1.00	1390	1.00	2622	1.00	1489	1.00	595	1.00	287	1.00	700	1.00	339	1.00	8639	1.00
Elec Interrupt	2	1.00	98	1.00	11	1.00	202	1.00	81	1.00	516	1.00	27	1.00	56	1.00	837	1.00	0	.00	1830	1.00
Fuel	69	1.00	211	1.00	340	1.00	346	1.00	933	1.00	3535	1.00	359	1.00	490	1.00	304	1.00	47	1.00	6633	1.00
Total Demand	1642	1.00	5282	1.00	5408	1.00	6486	1.00	18509	1.00	18376	1.00	4390	1.00	2675	1.00	6588	1.00	1199	1.00	70559	1.00
SUPPLIES																						
Production	0	.00	70	1.00	1292	1.00	1425	1.00	1132	1.00	45133	1.00	1907	1.00	5356	1.00	1166	1.00	9	1.00	57489	1.00
Imports	32	1.00	743	1.00	0	.00	0	.00	2085	1.00	370	1.00	0	.00	1225	.41	0	.00	2372	.98	6827	.89
Base Load LNG	240	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	840	1.00
Storage	0	.00	537	1.00	5583	.35	1300	.00	7185	.51	4445	.00	1789	.00	683	.00	1457	.00	178	.00	23157	.27
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	272	1.00	1349	1.00	6875	.48	2724	.52	10402	.66	50547	.91	3696	.52	7263	.81	2623	.44	2559	.92	88313	.80
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2001	.69	0	.00	58	.36	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2059	.68
From 3	0	.00	8148	.65	0	.00	24	.00	995	.72	0	.00	0	.00	0	.00	0	.00	0	.00	9167	.66
From 4	0	.00	0	.00	4601	1.00	0	.00	9905	.71	34	.18	0	.00	0	.00	0	.00	0	.00	14540	.80
From 5	0	.00	0	.00	4501	.79	0	.00	0	.00	0	.00	1528	.76	0	.00	0	.00	0	.00	6029	.78
From 6	0	.00	0	.00	0	.00	19466	.86	0	.00	0	.00	9192	.85	984	.17	4319	.96	0	.00	33961	.85
From 7	0	.00	0	.00	0	.00	0	.00	7252	1.00	160	.20	0	.00	360	.69	0	.00	0	.00	7772	.97
From 8	0	.00	0	.00	0	.00	0	.00	1363	1.00	1084	1.00	1040	1.00	0	.00	0	.00	324	.35	3811	.94
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2001	.69	8148	.65	9160	.89	19490	.86	19515	.84	1278	.88	11760	.85	1603	.26	5577	.97	324	.35		
PIPELINE FLOW OUT																						
To 1	0	.00	2001	.69	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2001	.69
To 2	0	.00	0	.00	8148	.65	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8148	.65
To 3	0	.00	58	.36	0	.00	4601	1.00	4501	.79	0	.00	0	.00	0	.00	0	.00	0	.00	9160	.89
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19466	.86	0	.00	0	.00	0	.00	0	.00	19490	.86
To 5	0	.00	0	.00	995	.72	9905	.71	0	.00	0	.00	7252	1.00	1363	1.00	0	.00	0	.00	19515	.84
To 6	0	.00	0	.00	0	.00	34	.18	0	.00	0	.00	160	.20	1084	1.00	0	.00	0	.00	1278	.88
To 7	0	.00	0	.00	0	.00	0	.00	1528	.76	9192	.85	0	.00	1040	1.00	0	.00	0	.00	11760	.85
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.17	360	.69	0	.00	0	.00	259	.00	1603	.26
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	4319	.96	0	.00	0	.00	0	.00	1258	1.00	5577	.97
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.35	0	.00	0	.00	324	.35
Total PL Out	0	.00	2059	.68	9167	.66	14540	.80	6029	.78	33961	.85	7772	.97	3811	.94	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 1991 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1726	1.00	4795	1.00	4347	1.00	4490	1.00	16828	1.00	6218	1.00	3718	1.00	2117	1.00	5635	1.00	1077	1.00	50948	1.00
Commercial	894	1.00	2552	1.00	2275	1.00	2636	1.00	8393	1.00	2677	1.00	1817	1.00	1352	1.00	1919	1.00	822	1.00	25337	1.00
Industrial Firm	161	.12	318	1.00	698	1.00	1298	1.00	1667	1.00	7979	1.00	364	1.00	131	1.00	1076	1.00	94	1.00	13784	.99
Elec Util Firm	0	.00	3	1.00	5	1.00	221	1.00	8	1.00	2139	1.00	5	1.00	3	1.00	73	1.00	0	.00	2456	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	112	.96	347	1.00	668	1.00	530	1.00	1588	1.00	4328	1.00	568	1.00	828	1.00	541	1.00	73	1.00	9582	1.00
Total Demand	2892	.95	8013	1.00	7992	1.00	9174	1.00	28484	1.00	23340	1.00	6472	1.00	4430	1.00	9243	1.00	2065	1.00	102109	1.00
SUPPLIES																						
Production	0	.00	70	1.00	1292	1.00	1425	1.00	1132	1.00	43281	1.00	1878	1.00	5356	1.00	1166	1.00	9	1.00	55608	1.00
Imports	32	1.00	743	1.00	0	.00	0	.00	2085	1.00	370	1.00	0	.00	1225	1.00	0	.00	2372	1.00	6827	1.00
Base Load LNG	280	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	980	1.00
Storage	0	.00	1008	1.00	11269	.70	3395	.77	17792	.97	10058	.28	2713	1.00	1870	.10	5100	.59	450	1.00	53655	.71
Peak Shaving	433	1.00	397	.17	473	.00	631	.00	657	.00	16	.00	203	.00	8	.00	39	.00	142	.39	2998	.19
Total Supply	745	1.00	2217	.85	13034	.70	5451	.74	21666	.95	54424	.87	4793	.96	8458	.80	6305	.66	2972	.97	120069	.85
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2001	1.00	0	.00	58	.36	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2059	.98
From 3	0	.00	8148	1.00	0	.00	24	.00	995	.72	0	.00	0	.00	0	.00	0	.00	0	.00	9167	.97
From 4	0	.00	0	.00	4601	.89	0	.00	9905	.62	34	.18	0	.00	0	.00	0	.00	0	.00	14540	.70
From 5	0	.00	0	.00	4501	.79	0	.00	0	.00	0	.00	1528	.76	0	.00	0	.00	0	.00	6029	.78
From 6	0	.00	0	.00	0	.00	19466	.79	0	.00	0	.00	9192	.54	984	.17	4319	.91	0	.00	33961	.72
From 7	0	.00	0	.00	0	.00	0	.00	7252	.64	160	.20	0	.00	360	.69	0	.00	0	.00	7772	.63
From 8	0	.00	0	.00	0	.00	0	.00	1363	.88	1084	.47	1040	.69	0	.00	0	.00	324	1.00	3811	.72
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.91	0	.00	1517	.75
Total PL In	2001	1.00	8148	1.00	9160	.84	19490	.79	19515	.65	1278	.43	11760	.58	1603	.26	5577	.91	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2001	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2001	1.00
To 2	0	.00	0	.00	8148	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8148	1.00
To 3	0	.00	58	.36	0	.00	4601	.89	4501	.79	0	.00	0	.00	0	.00	0	.00	0	.00	9160	.84
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19466	.79	0	.00	0	.00	0	.00	0	.00	19490	.79
To 5	0	.00	0	.00	995	.72	9905	.62	0	.00	0	.00	7252	.64	1363	.88	0	.00	0	.00	19515	.65
To 6	0	.00	0	.00	0	.00	34	.18	0	.00	0	.00	160	.20	1084	.47	0	.00	0	.00	1278	.43
To 7	0	.00	0	.00	0	.00	0	.00	1528	.76	9192	.54	0	.00	1040	.69	0	.00	0	.00	11760	.58
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.17	360	.69	0	.00	0	.00	259	.00	1603	.26
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	4319	.91	0	.00	0	.00	0	.00	1258	.91	5577	.91
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2059	.98	9167	.97	14540	.70	6029	.78	33961	.72	7772	.63	3811	.72	0	.00	1517	.75		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 1995 — LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	546	1.00	1568	1.00	1252	1.00	1029	1.00	4324	1.00	1170	1.00	886	1.00	557	1.00	1568	1.00	231	1.00	13130	1.00
Commercial	272	1.00	904	1.00	681	1.00	754	1.00	2204	1.00	818	1.00	575	1.00	362	1.00	849	1.00	203	1.00	7620	1.00
Industrial Firm	136	1.00	274	1.00	431	1.00	649	1.00	622	1.00	6711	1.00	178	1.00	117	1.00	1160	1.00	75	1.00	10352	1.00
Elec Util Firm	90	1.00	45	1.00	45	1.00	162	1.00	146	1.00	3141	1.00	16	1.00	13	1.00	106	1.00	0	.00	3766	1.00
Ind Interrupt	88	1.00	330	1.00	798	1.00	1633	1.00	2453	1.00	1604	1.00	617	1.00	314	1.00	694	1.00	333	1.00	8862	1.00
Elec Interrupt	208	1.00	806	1.00	112	1.00	354	1.00	176	1.00	849	1.00	88	1.00	104	1.00	1397	1.00	43	1.00	4133	1.00
Fuel	52	1.00	156	1.00	206	1.00	367	1.00	1973	1.00	3445	1.00	206	1.00	487	1.00	303	1.00	35	1.00	7229	1.00
Total Demand	1391	1.00	4084	1.00	3524	1.00	4948	1.00	11897	1.00	17737	1.00	2565	1.00	1952	1.00	6076	1.00	918	1.00	55096	1.00
SUPPLIES																						
Production	0	.00	66	1.00	1214	1.00	2962	1.00	1114	1.00	37826	1.00	1779	1.00	6698	.94	1236	1.00	10	1.00	52904	.99
Imports	32	1.00	1341	.83	0	.00	0	.00	2568	.00	370	.00	0	.00	1780	.00	0	.00	3102	.46	9193	.28
Base Load LNG	315	.00	0	.00	0	.00	0	.00	0	.00	600	.00	0	.00	0	.00	0	.00	0	.00	915	.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	.09	1406	.84	1213	1.00	2961	1.00	3682	.30	38796	.97	1779	1.00	8477	.74	1236	1.00	3111	.47	63012	.87
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.58	0	.00	183	.27	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.56
From 3	0	.00	8541	.50	0	.00	24	.00	995	.54	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.51
From 4	0	.00	0	.00	4601	.95	0	.00	10017	.52	34	.15	0	.00	0	.00	0	.00	0	.00	14652	.65
From 5	0	.00	0	.00	4661	.59	0	.00	0	.00	0	.00	1841	.57	0	.00	0	.00	0	.00	6502	.58
From 6	0	.00	0	.00	0	.00	19566	.59	0	.00	0	.00	9192	.66	984	.13	5065	.68	0	.00	34807	.61
From 7	0	.00	0	.00	0	.00	0	.00	7273	.99	160	.15	0	.00	360	.52	0	.00	0	.00	7793	.95
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	.77	324	1.00	4824	.97
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.68	0	.00	1517	.56
Total PL In	2344	.58	8541	.50	9445	.76	19590	.59	19961	.73	1278	.87	12073	.68	1603	.20	7023	.69	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.58	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.58
To 2	0	.00	0	.00	8541	.50	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.50
To 3	0	.00	183	.27	0	.00	4601	.95	4661	.59	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.76
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.59	0	.00	0	.00	0	.00	0	.00	19590	.59
To 5	0	.00	0	.00	995	.54	10017	.52	0	.00	0	.00	7273	.99	1676	1.00	0	.00	0	.00	19961	.73
To 6	0	.00	0	.00	0	.00	34	.15	0	.00	0	.00	160	.15	1084	1.00	0	.00	0	.00	1278	.87
To 7	0	.00	0	.00	0	.00	0	.00	1841	.57	9192	.66	0	.00	1040	1.00	0	.00	0	.00	12073	.68
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.13	360	.52	0	.00	0	.00	259	.00	1603	.20
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.68	0	.00	700	.77	0	.00	1258	.68	7023	.69
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2527	.56	9560	.51	14652	.65	6502	.58	34807	.61	7793	.95	4824	.97	0	.00	1517	.56		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 1995 — LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1097	1.00	3188	1.00	2622	1.00	2313	1.00	9486	1.00	2677	1.00	2043	1.00	1079	1.00	2644	1.00	427	1.00	27575	1.00
Commercial	482	1.00	1614	1.00	1298	1.00	1392	1.00	4706	1.00	1460	1.00	1092	1.00	687	1.00	1103	1.00	338	1.00	14171	1.00
Industrial Firm	173	1.00	379	1.00	620	1.00	883	1.00	1077	1.00	6770	1.00	264	1.00	146	1.00	1240	1.00	92	1.00	11643	1.00
Elec Util Firm	173	1.00	81	1.00	85	1.00	162	1.00	276	1.00	2119	1.00	23	1.00	13	1.00	78	1.00	0	.00	3011	1.00
Ind Interrupt	47	1.00	241	1.00	725	1.00	1329	1.00	2480	1.00	1516	1.00	610	1.00	316	1.00	666	1.00	310	1.00	8241	1.00
Elec Interrupt	2	1.00	106	1.00	14	1.00	149	1.00	149	1.00	511	1.00	33	1.00	242	1.00	897	1.00	0	.00	2103	1.00
Fuel	83	1.00	225	1.00	343	1.00	448	1.00	2449	1.00	3562	1.00	348	1.00	610	1.00	315	1.00	46	1.00	8429	1.00
Total Demand	2056	1.00	5834	1.00	5707	1.00	6676	1.00	20623	1.00	18615	1.00	4411	1.00	3094	1.00	6943	1.00	1211	1.00	75174	1.00
SUPPLIES																						
Production	0	.00	64	1.00	1183	1.00	2888	1.00	1087	1.00	36881	1.00	1735	1.00	6530	1.00	1206	1.00	9	1.00	51581	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2568	1.00	370	1.00	0	.00	1780	.47	0	.00	3102	.77	9193	.82
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	537	1.00	5583	.87	1300	1.00	7185	1.00	4445	.00	1789	.54	683	.00	1457	.23	178	.00	23157	.65
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1942	1.00	6766	.89	4187	1.00	10839	1.00	42295	.89	3523	.77	8993	.82	2662	.58	3289	.73	84846	.89
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.73	0	.00	183	.27	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.70
From 3	0	.00	8541	.66	0	.00	24	.00	995	.54	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.65
From 4	0	.00	0	.00	4601	.67	0	.00	10017	.79	34	.15	0	.00	0	.00	0	.00	0	.00	14652	.75
From 5	0	.00	0	.00	4661	.59	0	.00	0	.00	0	.00	1841	.57	0	.00	0	.00	0	.00	6502	.58
From 6	0	.00	0	.00	0	.00	19566	.69	0	.00	0	.00	9192	.36	984	.13	5065	.68	0	.00	34807	.58
From 7	0	.00	0	.00	0	.00	0	.00	7273	.48	160	.15	0	.00	360	.52	0	.00	0	.00	7793	.48
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	.26	4824	.95
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	.73	8541	.66	9445	.62	19590	.69	19961	.68	1278	.87	12073	.45	1603	.20	7023	.77	324	.26		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.73	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.73
To 2	0	.00	0	.00	8541	.66	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.66
To 3	0	.00	183	.27	0	.00	4601	.67	4661	.59	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.62
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.69	0	.00	0	.00	0	.00	0	.00	19590	.69
To 5	0	.00	0	.00	995	.54	10017	.79	0	.00	0	.00	7273	.48	1676	1.00	0	.00	0	.00	19961	.68
To 6	0	.00	0	.00	0	.00	34	.15	0	.00	0	.00	160	.15	1084	1.00	0	.00	0	.00	1278	.87
To 7	0	.00	0	.00	0	.00	0	.00	1841	.57	9192	.36	0	.00	1040	1.00	0	.00	0	.00	12073	.45
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.13	360	.52	0	.00	0	.00	259	.00	1603	.20
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.68	0	.00	700	1.00	0	.00	1258	1.00	7023	.77
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.26	0	.00	0	.00	324	.26
Total PL Out	0	.00	2527	.70	9560	.65	14652	.75	6502	.58	34807	.58	7793	.48	4824	.95	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 1995 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1843	1.00	5420	1.00	5008	1.00	4974	1.00	17644	1.00	6210	1.00	3595	1.00	1996	1.00	5764	1.00	964	1.00	53417	1.00
Commercial	891	1.00	2583	1.00	2271	1.00	2756	1.00	8470	1.00	2832	1.00	1801	1.00	1361	1.00	1798	1.00	828	1.00	25591	1.00
Industrial Firm	209	1.00	464	1.00	828	1.00	1315	1.00	1654	1.00	8111	1.00	382	1.00	182	1.00	1384	1.00	123	1.00	14652	1.00
Elec Util Firm	0	.00	3	1.00	5	1.00	162	1.00	13	1.00	2119	1.00	8	1.00	13	1.00	78	1.00	0	.00	2402	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	134	1.00	368	1.00	658	1.00	679	1.00	4134	1.00	4362	1.00	551	1.00	1057	1.00	558	1.00	71	1.00	12571	1.00
Total Demand	3076	1.00	8838	1.00	8770	1.00	9885	1.00	31915	1.00	23634	1.00	6337	1.00	4609	1.00	9582	1.00	1986	1.00	108635	1.00
SUPPLIES																						
Production	0	.00	64	1.00	1183	1.00	2888	1.00	1087	1.00	35368	1.00	1708	1.00	6530	1.00	1206	1.00	9	1.00	50041	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2568	1.00	370	1.00	0	.00	1780	1.00	0	.00	3102	1.00	9193	1.00
Base Load LNG	360	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	1060	1.00
Storage	0	.00	1008	1.00	11269	1.00	3395	1.00	17792	1.00	10058	.85	2713	1.00	1870	.00	5100	.59	450	.00	53655	.89
Peak Shaving	433	1.00	397	.47	473	.00	631	.00	657	.00	16	.00	203	.00	8	.00	39	.00	142	.00	2998	.21
Total Supply	825	1.00	2809	.92	12925	.96	6914	.91	22103	.97	46511	.97	4624	.96	10187	.82	6344	.67	3703	.84	116948	.93
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.96	0	.00	183	.27	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.91
From 3	0	.00	8541	1.00	0	.00	24	.00	995	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	9560	1.00
From 4	0	.00	0	.00	4601	.67	0	.00	10017	.81	34	.15	0	.00	0	.00	0	.00	0	.00	14652	.76
From 5	0	.00	0	.00	4661	.59	0	.00	0	.00	0	.00	1841	.57	0	.00	0	.00	0	.00	6502	.58
From 6	0	.00	0	.00	0	.00	19566	.76	0	.00	0	.00	9192	.38	984	.13	5065	.68	0	.00	34807	.63
From 7	0	.00	0	.00	0	.00	0	.00	7273	.48	160	.15	0	.00	360	.52	0	.00	0	.00	7793	.48
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	.48	1040	1.00	0	.00	700	1.00	324	.26	4824	.83
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.96	0	.00	1517	.80
Total PL In	2344	.96	8541	1.00	9445	.62	19590	.76	19961	.71	1278	.43	12073	.47	1603	.20	7023	.76	324	.26		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.96	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.96
To 2	0	.00	0	.00	8541	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	1.00
To 3	0	.00	183	.27	0	.00	4601	.67	4661	.59	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.62
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.76	0	.00	0	.00	0	.00	0	.00	19590	.76
To 5	0	.00	0	.00	995	1.00	10017	.81	0	.00	0	.00	7273	.48	1676	1.00	0	.00	0	.00	19961	.71
To 6	0	.00	0	.00	0	.00	34	.15	0	.00	0	.00	160	.15	1084	.48	0	.00	0	.00	1278	.43
To 7	0	.00	0	.00	0	.00	0	.00	1841	.57	9192	.38	0	.00	1040	1.00	0	.00	0	.00	12073	.47
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.13	360	.52	0	.00	0	.00	259	.00	1603	.20
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.68	0	.00	700	1.00	0	.00	1258	.96	7023	.76
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.26	0	.00	0	.00	324	.26
Total PL Out	0	.00	2527	.91	9560	1.00	14652	.76	6502	.58	34807	.63	7793	.48	4824	.83	0	.00	1517	.80		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 2000 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	580	1.00	1543	1.00	1195	1.00	970	1.00	4197	1.00	1106	1.00	858	1.00	551	1.00	1552	1.00	225	1.00	12776	1.00
Commercial	284	1.00	883	1.00	668	1.00	796	1.00	2199	1.00	803	1.00	569	1.00	358	1.00	871	1.00	191	1.00	7622	1.00
Industrial Firm	144	1.00	309	1.00	481	1.00	559	1.00	575	1.00	6232	1.00	165	1.00	136	1.00	1144	1.00	93	1.00	9836	1.00
Elec Util Firm	96	1.00	61	1.00	40	1.00	375	1.00	120	1.00	3282	1.00	43	1.00	287	1.00	144	1.00	0	.00	4447	1.00
Ind Interrupt	59	1.00	231	1.00	551	1.00	1271	1.00	2096	1.00	1474	1.00	572	1.00	301	1.00	724	1.00	301	1.00	7578	1.00
Elec Interrupt	130	1.00	476	1.00	157	1.00	362	1.00	266	1.00	875	1.00	114	1.00	101	1.00	1612	1.00	56	1.00	4149	1.00
Fuel	50	1.00	140	1.00	203	1.00	406	1.00	1971	1.00	3322	1.00	182	1.00	567	1.00	351	1.00	34	1.00	7227	1.00
Total Demand	1343	1.00	3642	1.00	3294	1.00	4739	1.00	11424	1.00	17094	1.00	2502	1.00	2300	1.00	6397	1.00	899	1.00	53637	1.00
SUPPLIES																						
Production	0	.00	68	1.00	1265	1.00	3607	1.00	1030	1.00	31868	1.00	1388	1.00	7577	.91	1775	1.00	14	1.00	48590	.99
Imports	32	1.00	1341	1.00	0	.00	0	.00	2568	1.00	370	.00	0	.00	2555	.00	0	.00	3102	.57	9968	.57
Base Load LNG	315	.00	0	.00	0	.00	0	.00	0	.00	600	.00	0	.00	0	.00	0	.00	0	.00	915	.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	.09	1409	1.00	1264	1.00	3607	1.00	3598	1.00	32837	.97	1387	1.00	10131	.68	1774	1.00	3115	.57	59473	.90
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.56	0	.00	183	.18	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.53
From 3	0	.00	8541	.42	0	.00	24	.00	995	.36	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.41
From 4	0	.00	0	.00	4601	.88	0	.00	10017	.58	34	.09	0	.00	0	.00	0	.00	0	.00	14652	.68
From 5	0	.00	0	.00	4661	.40	0	.00	0	.00	0	.00	1841	.38	0	.00	0	.00	0	.00	6502	.39
From 6	0	.00	0	.00	0	.00	19566	.56	0	.00	0	.00	9192	.22	984	.09	5065	.54	0	.00	34807	.46
From 7	0	.00	0	.00	0	.00	0	.00	7273	.34	160	.10	0	.00	360	.35	0	.00	0	.00	7793	.34
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	1.00	4824	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	.96	0	.00	1517	.80
Total PL In	2344	.56	8541	.42	9445	.63	19590	.56	19961	.52	1278	.86	12073	.31	1603	.13	7023	.66	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.56	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.56
To 2	0	.00	0	.00	8541	.42	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.42
To 3	0	.00	183	.18	0	.00	4601	.88	4661	.40	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.63
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.56	0	.00	0	.00	0	.00	0	.00	19590	.56
To 5	0	.00	0	.00	995	.36	10017	.58	0	.00	0	.00	7273	.34	1676	1.00	0	.00	0	.00	19961	.52
To 6	0	.00	0	.00	0	.00	34	.09	0	.00	0	.00	160	.10	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.38	9192	.22	0	.00	1040	1.00	0	.00	0	.00	12073	.31
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.09	360	.35	0	.00	0	.00	259	.00	1603	.13
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.54	0	.00	700	1.00	0	.00	1258	.96	7023	.66
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2527	.53	9560	.41	14652	.68	6502	.39	34807	.46	7793	.34	4824	1.00	0	.00	1517	.80		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 2000 LOW REFERENCE CASE

	REGION 1 Cap MMcfd	REGION 1 Util Rate	REGION 2 Cap MMcfd	REGION 2 Util Rate	REGION 3 Cap MMcfd	REGION 3 Util Rate	REGION 4 Cap MMcfd	REGION 4 Util Rate	REGION 5 Cap MMcfd	REGION 5 Util Rate	REGION 6 Cap MMcfd	REGION 6 Util Rate	REGION 7 Cap MMcfd	REGION 7 Util Rate	REGION 8 Cap MMcfd	REGION 8 Util Rate	REGION 9 Cap MMcfd	REGION 9 Util Rate	REGION 10 Cap MMcfd	REGION 10 Util Rate	TOTAL Cap MMcfd	TOTAL Util Rate
DEMAND																						
Residential	1165	1.00	3136	1.00	2503	1.00	2181	1.00	9208	1.00	2531	1.00	1979	1.00	1068	1.00	2618	1.00	414	1.00	26802	1.00
Commercial	504	1.00	1576	1.00	1273	1.00	1471	1.00	4696	1.00	1433	1.00	1080	1.00	680	1.00	1132	1.00	318	1.00	14163	1.00
Industrial Firm	177	1.00	403	1.00	645	1.00	749	1.00	971	1.00	6296	1.00	244	1.00	168	1.00	1216	1.00	113	1.00	10982	1.00
Elec Util Firm	185	1.00	103	1.00	97	1.00	604	1.00	294	1.00	2249	1.00	104	1.00	449	1.00	129	1.00	0	.00	4215	1.00
Ind Interrupt	32	1.00	169	1.00	500	1.00	1035	1.00	2119	1.00	1393	1.00	566	1.00	303	1.00	695	1.00	280	1.00	7090	1.00
Elec Interrupt	1	1.00	63	1.00	20	1.00	152	1.00	226	1.00	527	1.00	43	1.00	236	1.00	1036	1.00	0	.00	2303	1.00
Fuel	86	1.00	216	1.00	331	1.00	495	1.00	2424	1.00	3410	1.00	313	1.00	710	1.00	359	1.00	44	1.00	8388	1.00
Total Demand	2150	1.00	5665	1.00	5369	1.00	6687	1.00	19938	1.00	17838	1.00	4329	1.00	3613	1.00	7183	1.00	1169	1.00	73946	1.00
SUPPLIES																						
Production	0	.00	67	1.00	1233	1.00	3517	1.00	1005	1.00	31071	1.00	1353	1.00	7387	1.00	1730	1.00	13	1.00	47375	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2568	1.00	370	1.00	0	.00	2555	.22	0	.00	3102	.76	9968	.73
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	537	1.00	5583	1.00	1300	1.00	7185	1.00	4445	.19	1789	1.00	683	.00	1457	.80	178	.00	23157	.80
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1944	1.00	6815	1.00	4817	1.00	10757	1.00	36486	.90	3142	1.00	10625	.75	3187	.91	3293	.72	81415	.91
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.77	0	.00	183	.18	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.73
From 3	0	.00	8541	.65	0	.00	24	.00	995	.36	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.62
From 4	0	.00	0	.00	4601	.56	0	.00	10017	.73	34	.09	0	.00	0	.00	0	.00	0	.00	14652	.67
From 5	0	.00	0	.00	4661	.40	0	.00	0	.00	0	.00	1841	.38	0	.00	0	.00	0	.00	6502	.39
From 6	0	.00	0	.00	0	.00	19566	.60	0	.00	0	.00	9192	.22	984	.09	5065	.46	0	.00	34807	.46
From 7	0	.00	0	.00	0	.00	0	.00	7273	.33	160	.10	0	.00	360	.35	0	.00	0	.00	7793	.33
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	.18	4824	.94
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	.77	8541	.65	9445	.47	19590	.60	19961	.59	1278	.86	12073	.31	1603	.13	7023	.61	324	.18		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.77	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.77
To 2	0	.00	0	.00	8541	.65	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.65
To 3	0	.00	183	.18	0	.00	4601	.56	4661	.40	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.47
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.60	0	.00	0	.00	0	.00	0	.00	19590	.60
To 5	0	.00	0	.00	995	.36	10017	.73	0	.00	0	.00	7273	.33	1676	1.00	0	.00	0	.00	19961	.59
To 6	0	.00	0	.00	0	.00	34	.09	0	.00	0	.00	160	.10	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.38	9192	.22	0	.00	1040	1.00	0	.00	0	.00	12073	.31
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.09	360	.35	0	.00	0	.00	259	.00	1603	.13
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.46	0	.00	700	1.00	0	.00	1258	1.00	7023	.61
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.18	0	.00	0	.00	324	.18
Total PL Out	0	.00	2527	.73	9560	.62	14652	.67	6502	.39	34807	.46	7793	.33	4824	.94	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 2000 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1841	1.00	5425	1.00	5007	1.00	4973	1.00	17679	1.00	6200	1.00	3602	1.00	1986	1.00	5759	1.00	957	1.00	53427	1.00
Commercial	933	1.00	2521	1.00	2228	1.00	2912	1.00	8453	1.00	2781	1.00	1782	1.00	1347	1.00	1845	1.00	779	1.00	25581	1.00
Industrial Firm	201	1.00	464	1.00	790	1.00	1084	1.00	1465	1.00	7530	1.00	353	1.00	203	1.00	1366	1.00	141	1.00	13596	1.00
Elec Util Firm	0	.00	3	1.00	8	1.00	165	1.00	21	1.00	2184	1.00	8	1.00	13	1.00	90	1.00	0	.00	2492	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	138	1.00	351	1.00	623	1.00	736	1.00	4073	1.00	4174	1.00	496	1.00	1211	1.00	643	1.00	67	1.00	12512	1.00
Total Demand	3112	1.00	8764	1.00	8655	1.00	9870	1.00	31690	1.00	22868	1.00	6240	1.00	4759	1.00	9703	1.00	1944	1.00	107609	1.00
SUPPLIES																						
Production	0	.00	67	1.00	1233	1.00	3517	1.00	1005	1.00	29796	1.00	1332	1.00	7387	1.00	1730	1.00	13	1.00	46080	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2568	1.00	370	1.00	0	.00	2555	.68	0	.00	3102	1.00	9968	.92
Base Load LNG	360	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	1060	1.00
Storage	0	.00	1008	1.00	11269	1.00	3395	1.00	17792	1.00	10058	1.00	2713	1.00	1870	.00	5100	.72	450	.00	53655	.93
Peak Shaving	433	1.00	397	1.00	473	1.00	631	.00	657	.13	16	.00	203	.00	8	.00	39	.00	142	.00	2998	.46
Total Supply	825	1.00	2812	1.00	12975	1.00	7543	.92	22021	.97	40940	1.00	4248	.95	11820	.77	6869	.79	3707	.84	113762	.95
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.98	0	.00	183	.18	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.92
From 3	0	.00	8541	.97	0	.00	24	.00	995	.36	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.90
From 4	0	.00	0	.00	4601	.52	0	.00	10017	.84	34	.09	0	.00	0	.00	0	.00	0	.00	14652	.74
From 5	0	.00	0	.00	4661	.40	0	.00	0	.00	0	.00	1841	.38	0	.00	0	.00	0	.00	6502	.39
From 6	0	.00	0	.00	0	.00	19566	.71	0	.00	0	.00	9192	.32	984	.09	5065	.46	0	.00	34807	.55
From 7	0	.00	0	.00	0	.00	0	.00	7273	.32	160	.10	0	.00	360	.35	0	.00	0	.00	7793	.32
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	.27	4824	.95
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	.98	8541	.97	9445	.46	19590	.71	19961	.64	1278	.86	12073	.39	1603	.13	7023	.61	324	.27		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.98	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.98
To 2	0	.00	0	.00	8541	.97	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.97
To 3	0	.00	183	.18	0	.00	4601	.52	4661	.40	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.46
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.71	0	.00	0	.00	0	.00	0	.00	19590	.71
To 5	0	.00	0	.00	995	.36	10017	.84	0	.00	0	.00	7273	.32	1676	1.00	0	.00	0	.00	19961	.64
To 6	0	.00	0	.00	0	.00	34	.09	0	.00	0	.00	160	.10	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.38	9192	.32	0	.00	1040	1.00	0	.00	0	.00	12073	.39
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.09	360	.35	0	.00	0	.00	259	.00	1603	.13
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.46	0	.00	700	1.00	0	.00	1258	1.00	7023	.61
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.27	0	.00	0	.00	324	.27
Total PL Out	0	.00	2527	.92	9560	.90	14652	.74	6502	.39	34807	.55	7793	.32	4824	.95	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 2005 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	626	1.00	1546	1.00	1163	1.00	919	1.00	4103	1.00	1079	1.00	830	1.00	557	1.00	1547	1.00	218	1.00	12587	1.00
Commercial	321	1.00	968	1.00	726	1.00	861	1.00	2334	1.00	883	1.00	603	1.00	384	1.00	957	1.00	199	1.00	8235	1.00
Industrial Firm	208	1.00	341	1.00	535	1.00	620	1.00	548	1.00	6009	1.00	162	1.00	138	1.00	1218	1.00	112	1.00	9889	1.00
Elec Util Firm	122	1.00	112	1.00	170	1.00	612	1.00	239	1.00	4086	1.00	67	1.00	450	1.00	229	1.00	37	1.00	6123	1.00
Ind Interrupt	83	1.00	271	1.00	630	1.00	1394	1.00	1974	1.00	1415	1.00	545	1.00	298	1.00	620	1.00	277	1.00	7506	1.00
Elec Interrupt	255	1.00	912	.89	154	1.00	372	.91	274	1.00	976	1.00	112	1.00	104	1.00	1894	1.00	67	1.00	5120	.97
Fuel	63	1.00	166	1.00	226	1.00	416	1.00	1964	1.00	3667	1.00	173	1.00	640	1.00	427	1.00	37	1.00	7777	1.00
Total Demand	1677	1.00	4315	.98	3603	1.00	5194	.99	11436	1.00	18115	1.00	2491	1.00	2570	1.00	6891	1.00	945	1.00	57240	1.00
SUPPLIES																						
Production	0	.00	77	1.00	1416	1.00	3458	1.00	1333	1.00	32544	1.00	1240	1.00	8455	.86	2641	1.00	22	1.00	51185	.98
Imports	32	1.00	1341	1.00	0	.00	0	.00	2568	1.00	370	1.00	0	.00	2555	.00	0	.00	3102	.60	9968	.62
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1417	1.00	1416	1.00	3457	1.00	3901	1.00	33514	1.00	1240	1.00	11009	.66	2641	1.00	3123	.60	62068	.92
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.57	0	.00	183	.09	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.53
From 3	0	.00	8541	.49	0	.00	24	.00	995	.18	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.45
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.29	34	.06	0	.00	0	.00	0	.00	0	.00	14652	.51
From 5	0	.00	0	.00	4661	.41	0	.00	0	.00	0	.00	1841	.19	0	.00	0	.00	0	.00	6502	.35
From 6	0	.00	0	.00	0	.00	19566	.47	0	.00	0	.00	9192	.54	984	.04	5065	.45	0	.00	34807	.47
From 7	0	.00	0	.00	0	.00	0	.00	7273	.69	160	.05	0	.00	360	.17	0	.00	0	.00	7793	.65
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	1.00	4824	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	.57	8541	.49	9445	.69	19590	.47	19961	.49	1278	.86	12073	.52	1603	.06	7023	.61	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.57	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.57
To 2	0	.00	0	.00	8541	.49	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.49
To 3	0	.00	183	.09	0	.00	4601	1.00	4661	.41	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.69
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.47	0	.00	0	.00	0	.00	0	.00	19590	.47
To 5	0	.00	0	.00	995	.18	10017	.29	0	.00	0	.00	7273	.69	1676	1.00	0	.00	0	.00	19961	.49
To 6	0	.00	0	.00	0	.00	34	.06	0	.00	0	.00	160	.05	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.19	9192	.54	0	.00	1040	1.00	0	.00	0	.00	12073	.52
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.04	360	.17	0	.00	0	.00	259	.00	1603	.06
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.45	0	.00	700	1.00	0	.00	1258	1.00	7023	.61
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2527	.53	9560	.45	14652	.51	6502	.35	34807	.47	7793	.65	4824	1.00	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 2005 — LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1257	1.00	3143	1.00	2437	1.00	2067	1.00	9000	1.00	2470	1.00	1915	1.00	1079	1.00	2608	1.00	401	1.00	26376	1.00
Commercial	570	1.00	1727	1.00	1383	1.00	1590	1.00	4984	1.00	1577	1.00	1144	1.00	730	1.00	1244	1.00	332	1.00	15279	1.00
Industrial Firm	256	1.00	447	1.00	719	1.00	830	1.00	921	1.00	6075	1.00	239	1.00	171	1.00	1322	1.00	135	1.00	11115	1.00
Elec Util Firm	213	1.00	150	1.00	459	1.00	1413	1.00	627	1.00	3228	1.00	166	1.00	752	1.00	229	1.00	104	1.00	7340	1.00
Ind Interrupt	45	1.00	198	1.00	573	1.00	1135	1.00	1996	1.00	1338	1.00	539	1.00	300	1.00	595	1.00	258	1.00	6975	1.00
Elec Interrupt	3	1.00	120	1.00	20	1.00	156	1.00	233	1.00	588	1.00	42	1.00	242	1.00	1217	1.00	0	.00	2620	1.00
Fuel	98	1.00	230	1.00	369	1.00	527	1.00	2430	1.00	3757	1.00	304	1.00	802	1.00	436	1.00	49	1.00	9002	1.00
Total Demand	2440	1.00	6014	1.00	5959	1.00	7717	1.00	20191	1.00	19031	1.00	4350	1.00	4076	1.00	7650	1.00	1278	1.00	78710	1.00
SUPPLIES																						
Production	0	.00	75	1.00	1381	1.00	3371	1.00	1300	1.00	31731	1.00	1209	1.00	8244	1.00	2575	1.00	21	1.00	49906	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2568	1.00	370	1.00	0	.00	2555	.10	0	.00	3102	.80	9968	.71
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	537	1.00	5583	1.00	1300	1.00	7185	1.00	4445	.67	1789	1.00	683	.00	1457	1.00	178	.00	23157	.90
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1952	1.00	6963	1.00	4671	1.00	11053	1.00	37145	.96	2998	1.00	11481	.74	4032	1.00	3301	.76	83946	.94
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2344	.89	0	.00	183	.09	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2527	.83
From 3	0	.00	8541	.72	0	.00	24	.00	995	.18	0	.00	0	.00	0	.00	0	.00	0	.00	9560	.66
From 4	0	.00	0	.00	4601	.96	0	.00	10017	.16	34	.06	0	.00	0	.00	0	.00	0	.00	14652	.41
From 5	0	.00	0	.00	4661	.20	0	.00	0	.00	0	.00	1841	.19	0	.00	0	.00	0	.00	6502	.20
From 6	0	.00	0	.00	0	.00	19566	.46	0	.00	0	.00	9192	.76	984	.04	5065	.33	0	.00	34807	.51
From 7	0	.00	0	.00	0	.00	0	.00	7273	.96	160	.05	0	.00	360	.17	0	.00	0	.00	7793	.91
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	.09	4824	.94
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2344	.89	8541	.72	9445	.57	19590	.46	19961	.52	1278	.86	12073	.70	1603	.06	7023	.52	324	.09		
PIPELINE FLOW OUT																						
To 1	0	.00	2344	.89	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2344	.89
To 2	0	.00	0	.00	8541	.72	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8541	.72
To 3	0	.00	183	.09	0	.00	4601	.96	4661	.20	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.57
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.46	0	.00	0	.00	0	.00	0	.00	19590	.46
To 5	0	.00	0	.00	995	.18	10017	.16	0	.00	0	.00	7273	.96	1676	1.00	0	.00	0	.00	19961	.52
To 6	0	.00	0	.00	0	.00	34	.06	0	.00	0	.00	160	.05	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.19	9192	.76	0	.00	1040	1.00	0	.00	0	.00	12073	.70
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.04	360	.17	0	.00	0	.00	259	.00	1603	.06
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.33	0	.00	700	1.00	0	.00	1258	1.00	7023	.52
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.09	0	.00	0	.00	324	.09
Total PL Out	0	.00	2527	.83	9560	.66	14652	.41	6502	.20	34807	.51	7793	.91	4824	.94	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 2005 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1835	1.00	5405	1.00	5020	1.00	4961	1.00	17641	1.00	6199	1.00	3600	1.00	1996	1.00	5764	1.00	963	1.00	53383	1.00
Commercial	1054	1.00	2764	1.00	2419	1.00	3148	1.00	8971	1.00	3059	1.00	1888	1.00	1446	1.00	2028	1.00	813	1.00	27588	1.00
Industrial Firm	290	1.00	517	1.00	885	1.00	1198	1.00	1385	1.00	7260	1.00	345	1.00	204	1.00	1450	1.00	161	1.00	13693	1.00
Elec Util Firm	0	.00	3	.67	8	1.00	170	1.00	21	1.00	2437	1.00	8	1.00	13	1.00	106	1.00	0	.00	2766	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	158	1.00	376	1.00	698	1.00	780	1.00	4069	1.00	4593	1.00	479	1.00	1357	1.00	778	1.00	73	1.00	13361	1.00
Total Demand	3335	1.00	9064	1.00	9029	1.00	10256	1.00	32087	1.00	23547	1.00	6319	1.00	5017	1.00	10126	1.00	2009	1.00	110794	1.00
SUPPLIES																						
Production	0	.00	75	1.00	1381	1.00	3371	1.00	1300	1.00	30429	1.00	1190	1.00	8244	1.00	2575	1.00	21	1.00	48585	1.00
Imports	32	1.00	1341	1.00	0	.00	0	.00	2568	1.00	370	1.00	0	.00	2555	.52	0	.00	3102	1.00	9968	.88
Base Load LNG	360	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	1060	1.00
Storage	0	.00	1008	1.00	11269	1.00	3395	1.00	17792	1.00	10058	1.00	2713	1.00	1870	.00	5100	.87	450	.00	53655	.94
Peak Shaving	433	1.00	397	1.00	473	1.00	631	.00	657	.69	16	.00	203	.00	8	.00	39	.00	142	.00	2998	.58
Total Supply	825	1.00	2820	1.00	13122	1.00	7397	.91	22316	.99	41572	1.00	4106	.95	12676	.75	7714	.91	3715	.84	116267	.95
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2511	1.00	0	.00	183	.09	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2694	.94
From 3	0	.00	8771	1.00	0	.00	24	.00	995	.18	0	.00	0	.00	0	.00	0	.00	0	.00	9790	.91
From 4	0	.00	0	.00	4601	.85	0	.00	10017	.82	34	.06	0	.00	0	.00	0	.00	0	.00	14652	.83
From 5	0	.00	0	.00	4661	.20	0	.00	0	.00	0	.00	1841	.19	0	.00	0	.00	0	.00	6502	.20
From 6	0	.00	0	.00	0	.00	19566	.80	0	.00	0	.00	9192	.25	984	.04	5065	.23	0	.00	34807	.55
From 7	0	.00	0	.00	0	.00	0	.00	7273	.16	160	.05	0	.00	360	.17	0	.00	0	.00	7793	.16
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	.44	4824	.96
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2511	1.00	8771	1.00	9445	.51	19590	.80	19961	.56	1278	.86	12073	.30	1603	.06	7023	.44	324	.44		
PIPELINE FLOW OUT																						
To 1	0	.00	2511	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2511	1.00
To 2	0	.00	0	.00	8771	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8771	1.00
To 3	0	.00	183	.09	0	.00	4601	.85	4661	.20	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.51
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.80	0	.00	0	.00	0	.00	0	.00	19590	.80
To 5	0	.00	0	.00	995	.18	10017	.82	0	.00	0	.00	7273	.16	1676	1.00	0	.00	0	.00	19961	.56
To 6	0	.00	0	.00	0	.00	34	.06	0	.00	0	.00	160	.05	1084	1.00	0	.00	0	.00	1278	.86
To 7	0	.00	0	.00	0	.00	0	.00	1841	.19	9192	.25	0	.00	1040	1.00	0	.00	0	.00	12073	.30
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.04	360	.17	0	.00	0	.00	259	.00	1603	.06
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.23	0	.00	700	1.00	0	.00	1258	1.00	7023	.44
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.44	0	.00	0	.00	324	.44
Total PL Out	0	.00	2694	.94	9790	.91	14652	.83	6502	.20	34807	.55	7793	.16	4824	.96	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE DAY 2010 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	672	1.00	1553	1.00	1133	1.00	864	1.00	4020	1.00	1055	1.00	801	1.00	565	1.00	1544	1.00	212	1.00	12420	1.00
Commercial	333	1.00	1015	1.00	736	1.00	845	1.00	2351	1.00	919	1.00	605	1.00	397	1.00	958	1.00	200	1.00	8357	1.00
Industrial Firm	239	1.00	356	1.00	551	1.00	585	1.00	503	1.00	5567	1.00	146	1.00	136	1.00	1234	1.00	130	1.00	9448	1.00
Elec Util Firm	160	1.00	194	1.00	327	1.00	947	1.00	407	1.00	4572	1.00	104	1.00	543	1.00	335	1.00	83	1.00	7671	1.00
Ind Interrupt	75	1.00	255	1.00	556	1.00	1240	1.00	1750	1.00	1303	1.00	497	1.00	269	1.00	540	1.00	239	1.00	6724	1.00
Elec Interrupt	277	.00	899	.00	160	.00	428	1.00	301	1.00	950	1.00	114	1.00	112	1.00	2133	.77	80	1.00	5452	.66
Fuel	68	1.00	171	1.00	229	1.00	402	1.00	1961	1.00	3771	1.00	156	1.00	693	1.00	470	1.00	38	1.00	7958	1.00
Total Demand	1823	.85	4443	.80	3690	.96	5311	1.00	11292	1.00	18138	1.00	2423	1.00	2713	1.00	7214	.93	981	1.00	58032	.97
SUPPLIES																						
Production	0	.00	76	1.00	1413	1.00	3170	1.00	1290	1.00	30864	1.00	1015	1.00	9191	.82	3119	1.00	26	1.00	50164	.97
Imports	32	1.00	1805	1.00	0	.00	0	.00	2678	1.00	370	1.00	0	.00	3125	.00	0	.00	3102	.61	11112	.61
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	1881	1.00	1413	1.00	3169	1.00	3968	1.00	31834	1.00	1014	1.00	12315	.61	3119	1.00	3128	.61	62191	.90
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2511	.48	0	.00	183	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2694	.45
From 3	0	.00	8771	.33	0	.00	24	.00	995	.00	0	.00	0	.00	0	.00	0	.00	0	.00	9790	.29
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.60	34	.00	0	.00	0	.00	0	.00	0	.00	14652	.73
From 5	0	.00	0	.00	4661	.08	0	.00	0	.00	0	.00	1841	.00	0	.00	0	.00	0	.00	6502	.06
From 6	0	.00	0	.00	0	.00	19566	.65	0	.00	0	.00	9192	.04	984	.00	5065	.32	0	.00	34807	.42
From 7	0	.00	0	.00	0	.00	0	.00	7273	.00	160	.00	0	.00	360	.00	0	.00	0	.00	7793	.00
From 8	0	.00	0	.00	0	.00	0	.00	1676	1.00	1084	1.00	1040	1.00	0	.00	700	1.00	324	1.00	4824	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1258	1.00	0	.00	1517	.83
Total PL In	2511	.48	8771	.33	9445	.53	19590	.65	19961	.39	1278	.85	12073	.12	1603	.00	7023	.51	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2511	.48	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2511	.48
To 2	0	.00	0	.00	8771	.33	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8771	.33
To 3	0	.00	183	.00	0	.00	4601	1.00	4661	.08	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.53
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.65	0	.00	0	.00	0	.00	0	.00	19590	.65
To 5	0	.00	0	.00	995	.00	10017	.60	0	.00	0	.00	7273	.00	1676	1.00	0	.00	0	.00	19961	.39
To 6	0	.00	0	.00	0	.00	34	.00	0	.00	0	.00	160	.00	1084	1.00	0	.00	0	.00	1278	.85
To 7	0	.00	0	.00	0	.00	0	.00	1841	.00	9192	.04	0	.00	1040	1.00	0	.00	0	.00	12073	.12
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.00	360	.00	0	.00	0	.00	259	.00	1603	.00
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.32	0	.00	700	1.00	0	.00	1258	1.00	7023	.51
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2694	.45	9790	.29	14652	.73	6502	.06	34807	.42	7793	.00	4824	1.00	0	.00	1517	.83		

National Petroleum Council - Inter-Region Flow Analysis

AVERAGE JANUARY DAY 2010 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1350	1.00	3157	1.00	2374	1.00	1943	1.00	8819	1.00	2415	1.00	1848	1.00	1095	1.00	2604	1.00	391	1.00	25994	1.00
Commercial	590	1.00	1811	1.00	1402	1.00	1561	1.00	5020	1.00	1641	1.00	1148	1.00	756	1.00	1244	1.00	333	1.00	15504	1.00
Industrial Firm	292	1.00	463	1.00	726	1.00	778	1.00	837	1.00	5634	1.00	215	1.00	167	1.00	1355	1.00	156	1.00	10623	1.00
Elec Util Firm	255	1.00	218	1.00	885	1.00	2302	1.00	1133	1.00	4122	1.00	265	1.00	973	1.00	363	1.00	225	1.00	10741	1.00
Ind Interrupt	40	1.00	186	1.00	505	1.00	1009	1.00	1770	1.00	1232	1.00	492	1.00	271	1.00	518	1.00	223	1.00	6246	1.00
Elec Interrupt	3	1.00	118	1.00	20	1.00	180	1.00	256	1.00	572	1.00	43	1.00	261	1.00	1370	1.00	0	.00	2823	1.00
Fuel	104	1.00	232	1.00	379	1.00	523	1.00	2420	1.00	3849	1.00	279	1.00	866	1.00	472	1.00	52	1.00	9175	1.00
Total Demand	2633	1.00	6186	1.00	6292	1.00	8295	1.00	20253	1.00	19464	1.00	4290	1.00	4387	1.00	7927	1.00	1379	1.00	81109	1.00
SUPPLIES																						
Production	0	.00	75	1.00	1378	1.00	3090	1.00	1258	1.00	30093	1.00	989	1.00	8961	1.00	3041	1.00	26	1.00	48910	1.00
Imports	32	1.00	1805	1.00	0	.00	0	.00	2678	1.00	370	1.00	0	.00	3125	.37	0	.00	3102	.95	11112	.81
Base Load LNG	315	1.00	0	.00	0	.00	0	.00	0	.00	600	1.00	0	.00	0	.00	0	.00	0	.00	915	1.00
Storage	0	.00	537	1.00	5583	1.00	1300	1.00	7185	1.00	4445	1.00	1789	1.00	683	.00	1457	1.00	178	.00	23157	.96
Peak Shaving	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Total Supply	347	1.00	2416	1.00	6960	1.00	4390	1.00	11120	1.00	35507	1.00	2778	1.00	12769	.79	4498	1.00	3305	.90	84094	.96
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2511	.91	0	.00	183	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2694	.85
From 3	0	.00	8771	.69	0	.00	24	.00	995	.00	0	.00	0	.00	0	.00	0	.00	0	.00	9790	.62
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.05	34	.00	0	.00	0	.00	0	.00	0	.00	14652	.35
From 5	0	.00	0	.00	4661	.17	0	.00	0	.00	0	.00	1841	.00	0	.00	0	.00	0	.00	6502	.12
From 6	0	.00	0	.00	0	.00	19566	.46	0	.00	0	.00	9192	.81	984	.00	5065	.18	0	.00	34807	.50
From 7	0	.00	0	.00	0	.00	0	.00	7273	1.00	160	.00	0	.00	360	.00	0	.00	0	.00	7793	.93
From 8	0	.00	0	.00	0	.00	0	.00	2132	1.00	1379	1.00	1323	1.00	0	.00	891	1.00	324	.00	6049	.95
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1601	1.00	0	.00	1860	.86
Total PL In	2511	.91	8771	.69	9445	.57	19590	.46	20417	.49	1573	.88	12356	.71	1603	.00	7557	.45	324	.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2511	.91	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2511	.91
To 2	0	.00	0	.00	8771	.69	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8771	.69
To 3	0	.00	183	.00	0	.00	4601	1.00	4661	.17	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.57
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.46	0	.00	0	.00	0	.00	0	.00	19590	.46
To 5	0	.00	0	.00	995	.00	10017	.05	0	.00	0	.00	7273	1.00	2132	1.00	0	.00	0	.00	20417	.49
To 6	0	.00	0	.00	0	.00	34	.00	0	.00	0	.00	160	.00	1379	1.00	0	.00	0	.00	1573	.88
To 7	0	.00	0	.00	0	.00	0	.00	1841	.00	9192	.81	0	.00	1323	1.00	0	.00	0	.00	12356	.71
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.00	360	.00	0	.00	0	.00	259	.00	1603	.00
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.18	0	.00	891	1.00	0	.00	1601	1.00	7557	.45
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	.00	0	.00	0	.00	324	.00
Total PL Out	0	.00	2694	.85	9790	.62	14652	.35	6502	.12	34807	.50	7793	.93	6049	.95	0	.00	1860	.86		

National Petroleum Council - Inter-Region Flow Analysis

PEAK DAY 2010 LOW REFERENCE CASE

	REGION 1		REGION 2		REGION 3		REGION 4		REGION 5		REGION 6		REGION 7		REGION 8		REGION 9		REGION 10		TOTAL	
	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate	Cap MMcfd	Util Rate
DEMAND																						
Residential	1836	1.00	5430	1.00	5009	1.00	4973	1.00	17638	1.00	6206	1.00	3604	1.00	1992	1.00	5781	1.00	961	1.00	53430	1.00
Commercial	1091	1.00	2897	1.00	2453	1.00	3090	1.00	9036	1.00	3183	1.00	1894	1.00	1496	1.00	2028	1.00	815	1.00	27985	1.00
Industrial Firm	322	1.00	530	1.00	871	1.00	1105	1.00	1247	1.00	6725	1.00	310	1.00	197	1.00	1467	1.00	178	1.00	12952	1.00
Elec Util Firm	0	.00	3	1.00	11	1.00	194	1.00	24	1.00	2371	1.00	8	1.00	16	1.00	118	1.00	0	.00	2744	1.00
Ind Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Elec Interrupt	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
Fuel	167	1.00	379	1.00	710	1.00	768	1.00	4033	1.00	4698	1.00	438	1.00	1456	1.00	844	1.00	77	1.00	13569	1.00
Total Demand	3415	1.00	9238	1.00	9053	1.00	10130	1.00	31978	1.00	23183	1.00	6254	1.00	5157	1.00	10238	1.00	2031	1.00	110681	1.00
SUPPLIES																						
Production	0	.00	75	1.00	1378	1.00	3090	1.00	1258	1.00	28858	1.00	974	1.00	8961	1.00	3041	1.00	26	1.00	47660	1.00
Imports	32	1.00	1805	1.00	0	.00	0	.00	2678	1.00	370	1.00	0	.00	3125	.72	0	.00	3102	1.00	11112	.92
Base Load LNG	360	1.00	0	.00	0	.00	0	.00	0	.00	700	1.00	0	.00	0	.00	0	.00	0	.00	1060	1.00
Storage	0	.00	1008	1.00	11269	1.00	3395	1.00	17792	1.00	10058	1.00	2713	1.00	1870	.00	5100	.96	450	.00	53655	.95
Peak Shaving	433	1.00	397	.44	473	.00	631	.00	657	.00	16	.00	203	.00	8	.00	39	.00	142	.00	2998	.20
Total Supply	825	1.00	3284	.93	13120	.96	7116	.91	22384	.97	40001	1.00	3890	.95	13963	.80	8180	.97	3719	.84	116486	.95
PIPELINE FLOW IN																						
From 1	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 2	2591	1.00	0	.00	183	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2774	.93
From 3	0	.00	8771	1.00	0	.00	24	.00	995	.00	0	.00	0	.00	0	.00	0	.00	0	.00	9790	.90
From 4	0	.00	0	.00	4601	1.00	0	.00	10017	.87	34	.00	0	.00	0	.00	0	.00	0	.00	14652	.91
From 5	0	.00	0	.00	4661	.12	0	.00	0	.00	0	.00	1841	.00	0	.00	0	.00	0	.00	6502	.09
From 6	0	.00	0	.00	0	.00	19566	.87	0	.00	0	.00	9192	.14	984	.00	5065	.00	0	.00	34807	.52
From 7	0	.00	0	.00	0	.00	0	.00	7273	.00	160	.00	0	.00	360	.00	0	.00	0	.00	7793	.00
From 8	0	.00	0	.00	0	.00	0	.00	2132	1.00	1379	1.00	1323	1.00	0	.00	891	1.00	324	1.00	6049	1.00
From 9	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00
From 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	259	.00	1601	.89	0	.00	1860	.76
Total PL In	2591	1.00	8771	1.00	9445	.55	19590	.86	20417	.53	1573	.88	12356	.21	1603	.00	7557	.31	324	1.00		
PIPELINE FLOW OUT																						
To 1	0	.00	2591	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	2591	1.00
To 2	0	.00	0	.00	8771	1.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	8771	1.00
To 3	0	.00	183	.00	0	.00	4601	1.00	4661	.12	0	.00	0	.00	0	.00	0	.00	0	.00	9445	.55
To 4	0	.00	0	.00	24	.00	0	.00	0	.00	19566	.87	0	.00	0	.00	0	.00	0	.00	19590	.86
To 5	0	.00	0	.00	995	.00	10017	.87	0	.00	0	.00	7273	.00	2132	1.00	0	.00	0	.00	20417	.53
To 6	0	.00	0	.00	0	.00	34	.00	0	.00	0	.00	160	.00	1379	1.00	0	.00	0	.00	1573	.88
To 7	0	.00	0	.00	0	.00	0	.00	1841	.00	9192	.14	0	.00	1323	1.00	0	.00	0	.00	12356	.21
To 8	0	.00	0	.00	0	.00	0	.00	0	.00	984	.00	360	.00	0	.00	0	.00	259	.00	1603	.00
To 9	0	.00	0	.00	0	.00	0	.00	0	.00	5065	.00	0	.00	891	1.00	0	.00	1601	.89	7557	.31
To 10	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	0	.00	324	1.00	0	.00	0	.00	324	1.00
Total PL Out	0	.00	2774	.93	9790	.90	14652	.91	6502	.09	34807	.52	7793	.00	6049	1.00	0	.00	1860	.76		

U.S. TRANSMISSION CAPACITY/INVESTMENT REQUIREMENTS

Based on NPC High Reference Cases

U.S. SUMMARY

(Volumes are MMcf/d, Investments in 1991 Millions U.S.)

ROUTE FROM	ROUTE TO	BASE 1991	PLANNED ADDITIONS 1992	INCREMENTAL FORECASTED PEAK DAY ADDITIONS 1993-1995	1996-2000	2001-2005	2006-2010	DISTANCE MILES	UNIT RATE ($/Mcf/Mi)	TOTAL FORECASTED INVEST (MM$)
Canada	NY/NJ	743	598	0	0	0	776	284	$1.40	$309
NY/NJ	New England	2,001	343	0	0	267	181	170	$1.40	$107
	Mid Atlantic	58	125	0	0	0	0			
Mid Atlantic	NY/NJ	8,148	393	0	0	761	0	284	$1.40	$303
	S. Atlantic	24	0	0	0	0	0			
	Midwest	995	0	0	0	0	0			
S. Atlantic	Mid Atlantic	4,601	0	0	0	0	0	595	$1.40	$0
	Midwest	9,905	112	0	0	0	0	482	$1.40	$0
	SW Central	34	0	0	0	0	0			
Canada	Midwest	2,085	418	64	0	115	137	709	$1.40	$314
Midwest	Mid Atlantic	4,501	160	0	0	0	0	482	$1.40	$0
	Central	1,528	313							
SW Central	S. Atlantic	19,466	100	0	0	0	0	1,049	$1.40	$0
	Central	9,192	0	0	0	0	0			
	N. Central	984	0	0	0	0	0	936	$1.40	$0
	S. Pacific	4,319	746	0	0	0	0	765	$1.40	$0
Central	Midwest	7,252	21	0	0	0	0	851	$1.40	$0
	SW Central	160	0	0	0	0	0	652	$1.40	$0
	N. Central	360	0	0	0	0	0			
Canada	N. Central	1,225	255	300	698	0	401	267	$1.25	$467
N. Central	Midwest	1,363	313	0	0	494	1,452	1,163	$1.40	$3,168
	SW Central	1,084	0	0	0	300	940	1,021	$1.40	$1,772
	Central	1,040	0	0	0	288	901	794	$1.25	$1,180
	S. Pacific	0	700	0	0	194	607	595	$1.25	$596
	Pacific NW	324	0	0	0	0	0			
Canada	Pacific NW	2,372	0	654	131	170	312	284	$1.40	$504
Pacific NW	N. Central	259	0	0	0	0	0	935	$1.40	$0
	S. Pacific	1,258	0	0	0	348	912	907	$1.40	$1,600
INVESTMENT (MM$)				**$424**	**$285**	**$2,653**	**$6,957**			**$10,319**

(Calculated for each period)

PROJECTED INVESTMENT REQUIREMENTS

Based on NPC High Reference Cases
(Investments in Millions of 1991 Dollars)

U.S. TRANSMISSION

ROUTE		PLANNED INVESTMENT	PROJECTED INCREMENTAL INVESTMENT				
FROM	TO	1992	1993-1995	1996-2000	2001-2005	2006-2010	TOTAL
Canada	NY/NJ	$310	$0	$0	$0	$309	$309
NY/NJ	New England	$257	$0	$0	$64	$43	$107
Mid Atlantic	NY/NJ	$87	$0	$0	$303	$0	$303
Canada	Midwest	$219	$64	$0	$114	$136	$314
Canada	N. Central	$46	$100	$233	$0	$134	$467
N. Cental	Midwest	$56	$0	$0	$804	$2,364	$3,168
	SW Cental	$0	$0	$0	$429	$1,344	$1,772
	Central	$0	$0	$0	$286	$894	$1,180
	Pacific	$853	$0	$0	$144	$451	$596
Canada	Pacific NW	$0	$260	$52	$68	$124	$504
Pacific NW	Pacific	$0	$0	$0	$442	$1,158	$1,600
OTHER		$1,191	-	-	-	-	-
Total Trans. Investiment		$3,019	$424	$285	$2,653	$6,957	$10,319
U.S. Storage Investment		NA	$0	$0	$0	$2,201	$2,201
TOTAL U.S. INVESTMENT		$3,019	$424	$285	$2,653	$9,158	$12,520
GRAND TOTAL							**$15,539**

PROJECTED INVESTMENT REQUIREMENTS

Based on NPC Low Reference Cases
(Millions of 1991 Dollars)

U.S. TRANSMISSION

ROUTE		PLANNED INVESTMENT	PROJECTED INCREMENTAL INVESTMENT				
FROM	TO	1992	1993-1995	1996-2000	2001-2005	2006-2010	TOTAL
Canada	NY/NJ	$310	$0	$0	$0	$0	$0
NY/NJ	New England	$257	$0	$0	$40	$19	$59
Mid Atlantic	NY/NJ	$87	$0	$0	$91	$0	$91
Canada	Midwest	$219	$65	$0	$0	$109	$174
Canada	N. Central	$46	$100	$233	$0	$100	$433
N. Cental	Midwest	$56	$0	$0	$0	$742	$742
	SW Cental	$0	$0	$0	$0	$422	$422
	Central	$0	$0	$0	$0	$281	$281
	Pacific	$853	$0	$0	$0	$142	$142
Canada	Pacific NW	$0	$290	$0	$0	$0	$290
Pacific NW	Pacific	$0	$0	$0	$0	$436	$436
OTHER		$1,191	-	-	-	-	-
Total Trans. Investiment		$3,019	$455	$233	$131	$2,251	$3,070
U.S. Storage Investment		NA	$0	$0	$0	$0	$0
TOTAL U.S. INVESTMENT		$3,019	$455	$233	$131	$2,251	$3,070
GRAND TOTAL							**$6,089**

HIGH REFERENCE PEAK/AVG. DAY STUDY RESULTS

Additional Storage/Pk Shaving Capability Requirements

(Volumes are MMcf/d, Investments in Millions of1991 Dollars)

U.S.

Storage Requirements (for Peak Day Capacity)

(peak day)	DELIVERABILITY 1991	ADDITIONS 1992	INCREMENTAL FORECASTED ADDITIONS 1993-1995	1996-2000	2001-2005	2006-2010	UNIT RATE ($/Mcf/d)	FORECASTED INVEST.*
New England	0	-	-	-	-	0	$4.00	$0
NY,NJ	1,008	-	-	-	-	10	$4.00	$5
Mid Atlantic	11,269	-	-	-	-	105	$4.00	$50
S. Atlantic	3,395	-	-	-	-	105	$4.00	$50
Midwest	17,792	-	-	-	-	135	$4.00	$65
SW Central	10,058	-	-	-	-	358	$4.00	$172
Central	2,713	-	-	-	-	39	$4.00	$19
N. Central	1,870	-	-	-	-	0	$4.00	$0
Pacific	5,100	-	-	-	-	117	$4.00	$56
Pacific NW	450	-	-	-	-	0	$4.00	$0
Total Deliverability Req'd	53,655 MMcf/d	-	-	-	-	869 MMcf/d		
Volume Gas						X 120 Days		
To Support Peak Day						104 Bcf	$4.00	$417
To Support Supply Balancing (1992-2010)						446 Bcf	$4.00	$1,784
U.S. STORAGE GRAND TOTAL						**550 Bcf**		**$2,201**

Peak Shaving Requirements

	PEAK DAY 1991	ADDITIONS 1992	INCREMENTAL FORECASTED ADDITIONS 1993-1995	1996-2000	2001-2005	2006-2010	UNIT RATE ($/Mcf/d)	FORECASTED INVEST.
New England	1,827	-	-	-	-	-	$400	-
NY,NJ	1,680	-	-	-	-	-	$400	-
Mid Atlantic	2,005	-	-	-	-	-	$400	-
S. Atlantic	2,675	-	-	-	-	-	$400	-
Midwest	2,783	-	-	-	-	-	$400	-
SW Central	67	-	-	-	-	-	$400	-
Central	861	-	-	-	-	-	$400	-
N. Central	33	-	-	-	-	-	$400	-
Pacific	167	-	-	-	-	-	$400	-
Pacific NW	601	-	-	-	-	-	$400	-
U.S. TOTAL	**12,699**	-	-	-	-	-	$400	-

U.S. TRANSMISSION CAPACITY/INVESTMENT REQUIREMENTS

U.S. SUMMARY

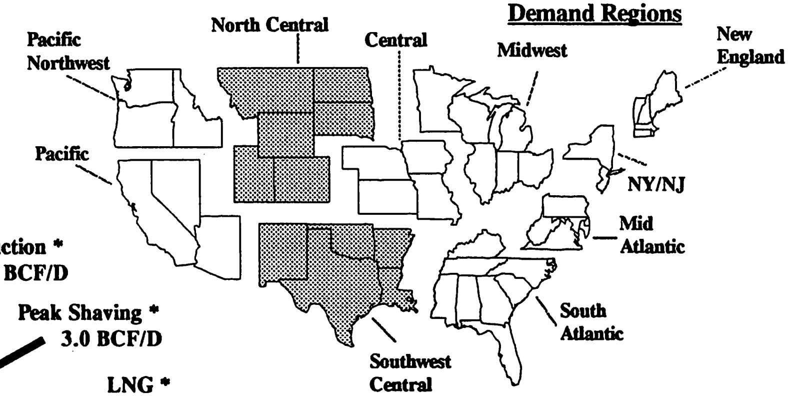
Based on NPC Low Reference Cases

(Volumes are MMCF/D, Investments in 1991 Millions U.S.)

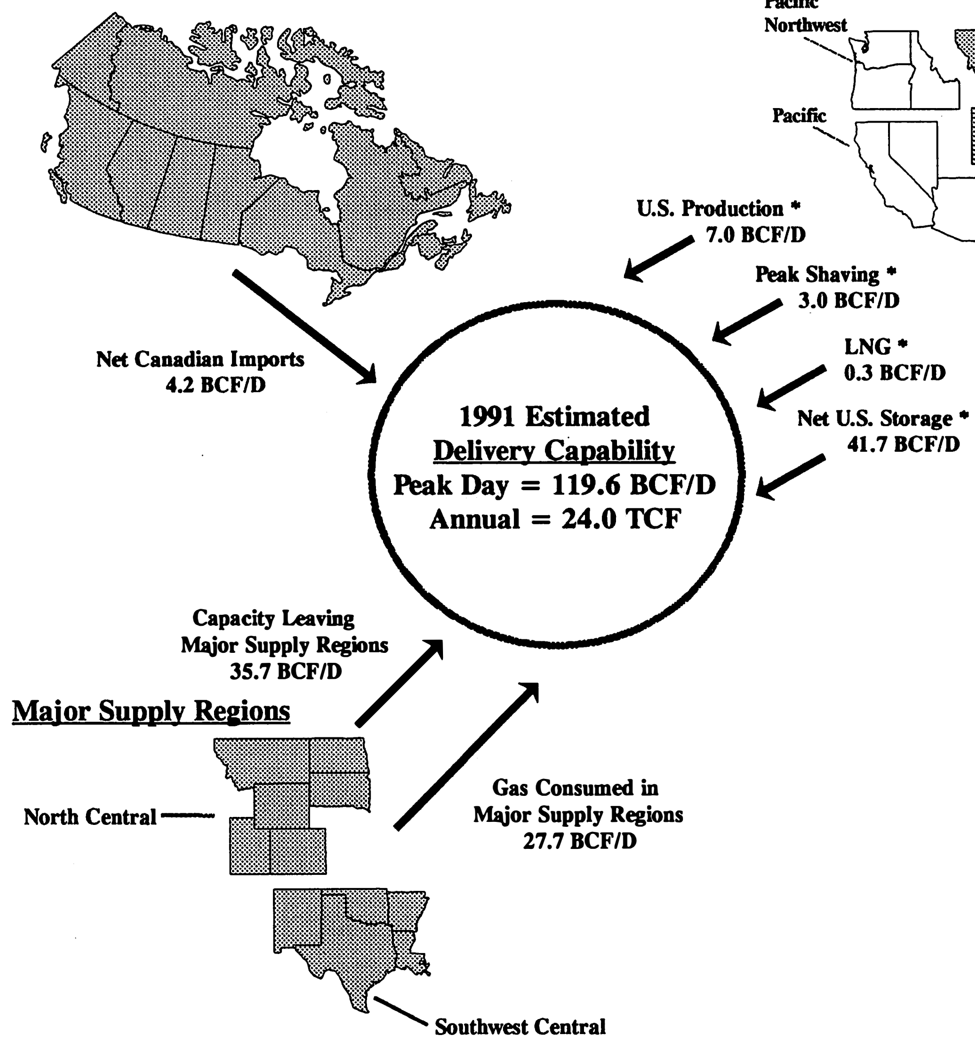
ROUTE FROM	ROUTE TO	BASE 1991	PLANNED ADDITIONS 1992-1994	INCREMENTAL FORECASTED PEAK DAY ADDITIONS 1995	1996-2000	2001-2005	2006-2010	DISTANCE MILES	UNIT RATE ($/MCF/Mi)	TOTAL FORECASTED INVEST (MM$)
Canada	NY/NJ	743	598	0	0	0	0	284	$1.40	$0
NY/NJ	New England	2,001	343	0	0	167	80	170	$1.40	$59
	Mid Atlantic	58	125	0	0	0	0			
Mid Atlantic	NY/NJ	8,148	393	0	0	230	0	284	$1.40	$91
	S. Atlantic	24	0	0	0	0	0			
	Midwest	995	0	0	0	0	0			
S. Atlantic	Mid Atlantic	4,601	0	0	0	0	0	595	$1.40	$0
	Midwest	9,905	112	0	0	0	0	482	$1.40	$0
	SW Central	34	0	0	0	0	0			
Canada	Midwest	2,085	418	65	0	0	110	709	$1.40	$174
Midwest	Mid Atlantic	4,501	160	0	0	0	0	482	$1.40	$0
	Central	1,528	313							
SW Central	S. Atlantic	19,466	100	0	0	0	0	1,049	$1.40	$0
	Central	9,192	0	0	0	0	0			
	N. Central	984	0	0	0	0	0	936	$1.40	$0
	Pacific	4,319	746	0	0	0	0	765	$1.40	$0
Central	Midwest	7,252	21	0	0	0	0	851	$1.40	$0
	SW Central	160	0	0	0	0	0	652	$1.40	$0
	N. Central	360	0	0	0	0	0			
Canada	N. Central	1,225	255	300	698	0	300	267	$1.25	$433
N. Central	Midwest	1,363	313	0	0	0	456	1,163	$1.40	$742
	SW Central	1,084	0	0	0	0	295	1,021	$1.40	$422
	Central	1,040	0	0	0	0	283	794	$1.25	$281
	Pacific	0	700	0	0	0	191	595	$1.25	$142
	Pacific NW	324	0	0	0	0	0			
Canada	Pacific NW	2,372	0	730	0	0	0	284	$1.40	$290
Pacific NW	N. Central	259	0	0	0	0	0	935	$1.40	$0
	Pacific	1,258	0	0	0	0	343	907	$1.40	$436
INVESTMENT (MM$)				$424	$285	$2,653	$6,957			$3,070

(Calculated for each period)

National Petroleum Council
1991 Estimated U.S. Capability to Transport Natural Gas
(Based on NPC High Reference Case)



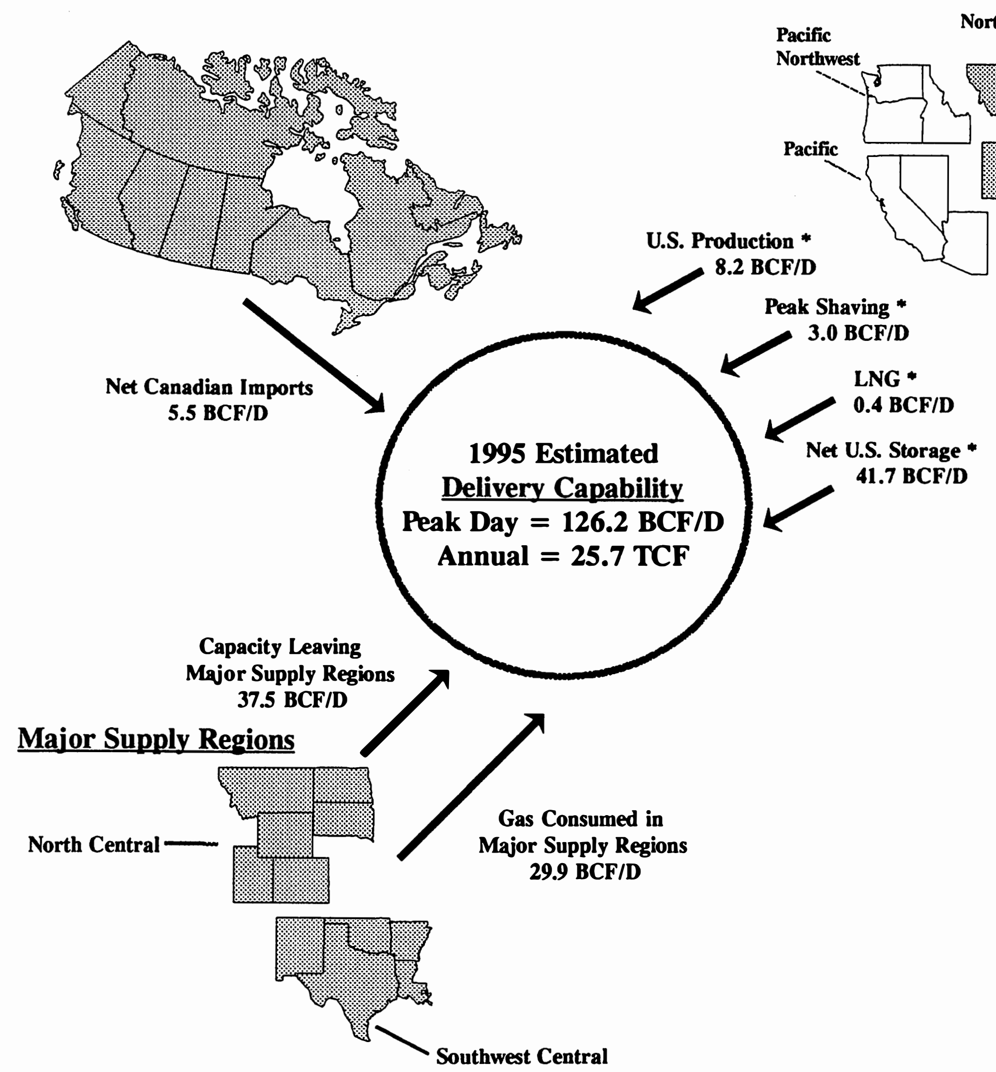
*Note: Excludes deliveries from SW Central and N. Central Regions

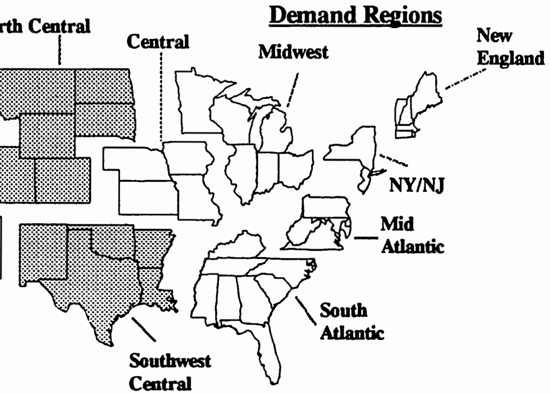


U. S. Delivery Capability Calculation	Peak Day (BCF/D)	Annual (TCF)
Leaving/Consumed in Major Supply Regions		
Capacity Leaving SW Central Region (1)	33.0	11.4
Capacity Leaving N. Central Region (1)	2.7	0.9
Gas Consumed in SW Central Region	23.3	6.6
Gas Consumed in N. Central Region	4.4	0.9
Net SW Central / N. Central Capacity	63.4	19.8
Canadian Imports		
Capacity from All of Canada (1)	6.4	2.2
Less Canadian import to N. Central	(1.2)	(0.4)
Less Re-exports to Canada (1)	(1.0)	(0.3)
Net Canadian Imports	4.2	1.5
Demand Region Deliverability		
Total U. S. Storage Withdrawal	53.7	0.0
Less SW Central and N. Central	(12.0)	0.0
Net U. S. Storage (2)	41.7	0.0
U. S. Production (3)	7.0	2.6
Peak Shaving (3)	3.0	0.0
LNG (3)	0.3	0.1
Grand Total	**119.6**	**24.0**

(1) Annual volume assumes peak day capacity at 95% load factor
(2) Assumed no contribution from storage on an annual basis
(3) Less Contributions from SW Central & N. Central

National Petroleum Council
1995 Estimated U.S. Capability to Transport Natural Gas
(Based on NPC High Reference Case)





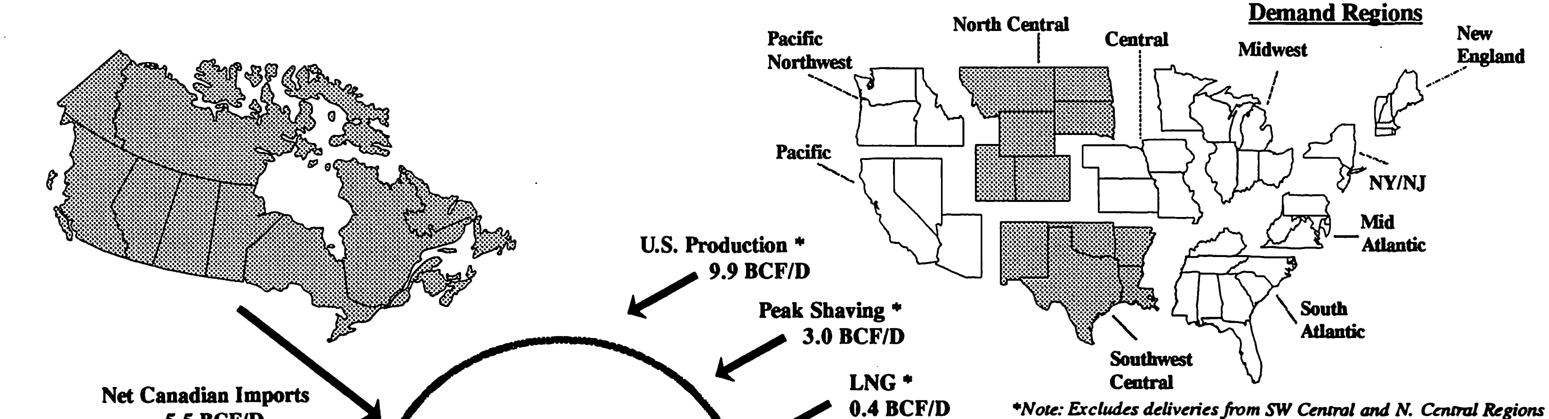
Note: Excludes deliveries from SW Central and N. Central Regions

U. S. Delivery Capability Calculation

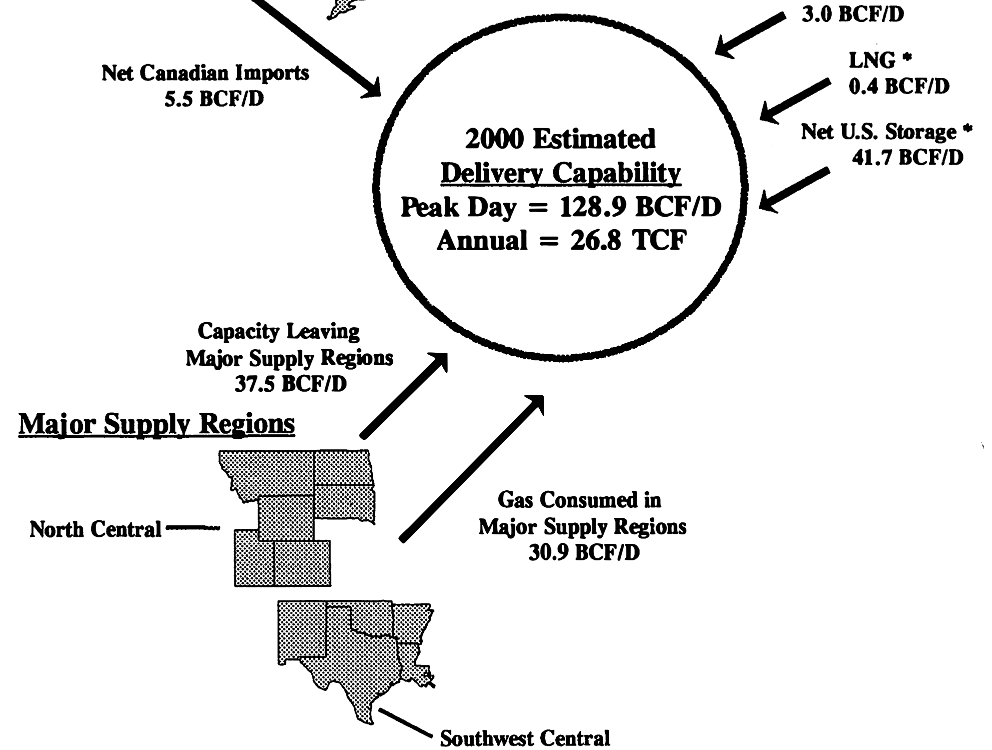
	Peak Day (BCF/D)	Annual (TCF)
Leaving/Consumed in Major Supply Regions		
Capacity Leaving SW Central Region (1)	33.8	11.7
Capacity Leaving N. Central Region (1)	3.7	1.3
Gas Consumed in SW Central Region	25.0	6.8
Gas Consumed in N. Central Region	4.9	0.8
Net SW Central / N. Central Capacity	67.4	20.6
Canadian Imports		
Capacity from All of Canada (1)	8.8	3.0
Less Canadian import to N. Central	(1.8)	(0.6)
Less Re-exports to Canada (1)	(1.5)	(0.5)
Net Canadian Imports	5.5	1.9
Demand Region Deliverability		
Total U. S. Storage Withdrawal	53.7	0.0
Less SW Central and N. Central	(12.0)	0.0
Net U. S. Storage (2)	41.7	0.0
U. S. Production (3)	8.2	3.1
Peak Shaving (3)	3.0	0.0
LNG (3)	0.4	0.1
Grand Total	**126.2**	**25.7**

(1) Annual volume assumes peak day capacity at 95% load factor
(2) Assumed no contribution from storage on an annual basis
(3) Less Contributions from SW Central & N. Central

National Petroleum Council
2000 Estimated U.S. Capability to Transport Natural Gas
(Based on NPC High Reference Case)



Note: Excludes deliveries from SW Central and N. Central Regions

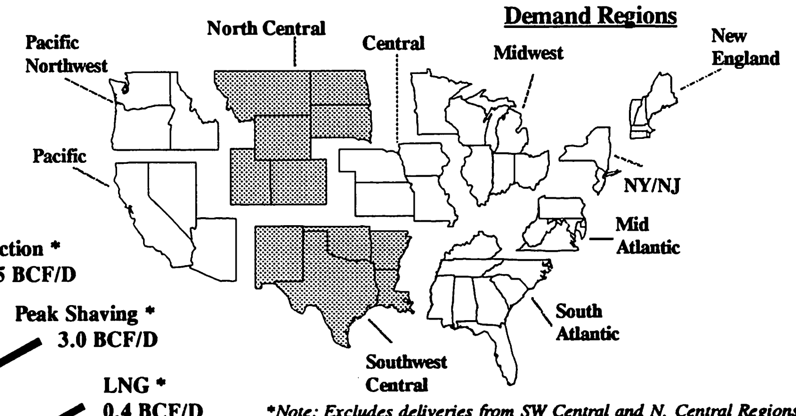


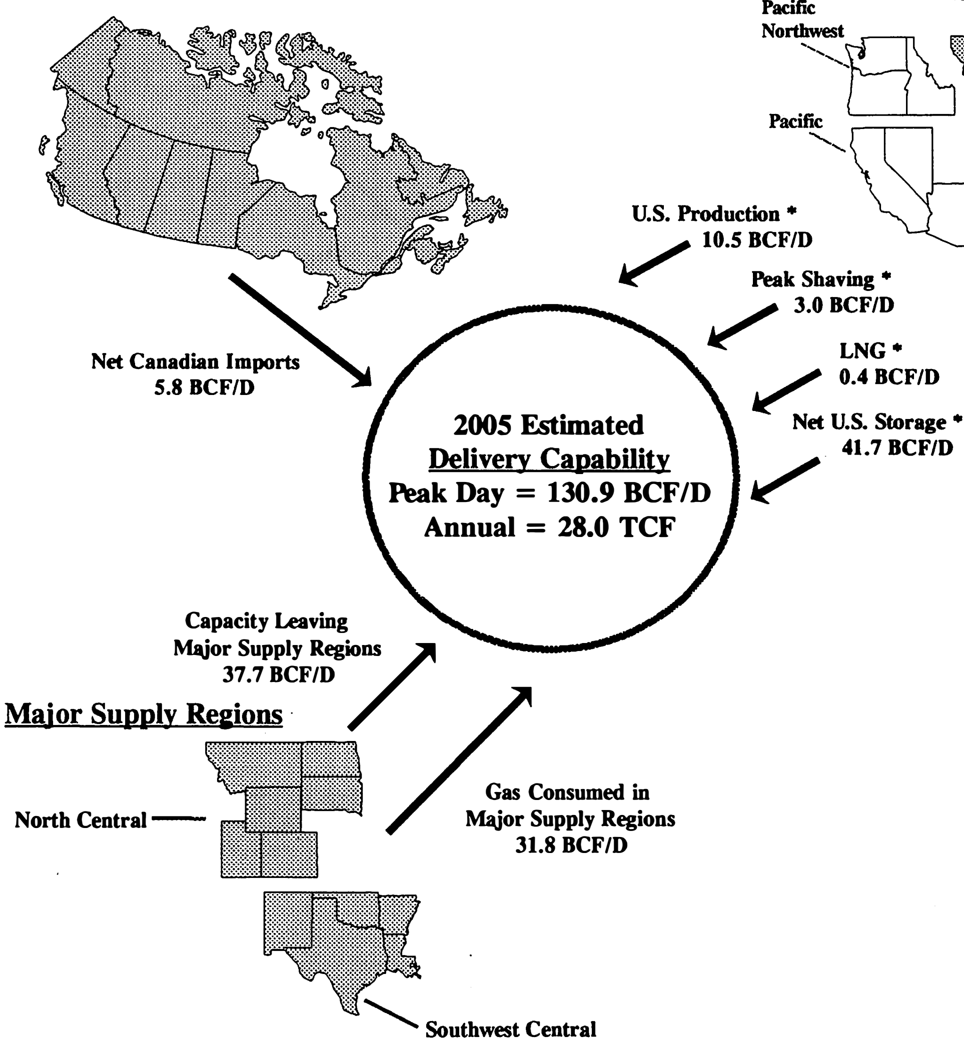
U. S. Delivery Capability Calculation

	Peak Day (BCF/D)	Annual (TCF)
Leaving/Consumed in Major Supply Regions		
Capacity Leaving SW Central Region (1)	33.8	11.7
Capacity Leaving N. Central Region (1)	3.7	1.3
Gas Consumed in SW Central Region	25.6	7.1
Gas Consumed in N. Central Region	5.3	1.0
Net SW Central / N. Central Capacity	68.4	21.1
Canadian Imports		
Capacity from All of Canada (1)	9.6	3.3
Less Canadian import to N. Central	(2.5)	(0.9)
Less Re-exports to Canada (1)	(1.6)	(0.5)
Net Canadian Imports	5.5	1.9
Demand Region Deliverability		
Total U. S. Storage Withdrawal	53.7	0.0
Less SW Central and N. Central	(12.0)	0.0
Net U. S. Storage (2)	41.7	0.0
U. S. Production (3)	9.9	3.7
Peak Shaving (3)	3.0	0.0
LNG (3)	0.4	0.1
Grand Total	**128.9**	**26.8**

(1) Annual volume assumes peak day capacity at 95% load factor
(2) Assumed no contribution from storage on an annual basis
(3) Less Contributions from SW Central & N. Central

National Petroleum Council
2005 Estimated U.S. Capability to Deliver Natural Gas
(Based on NPC High Reference Case)



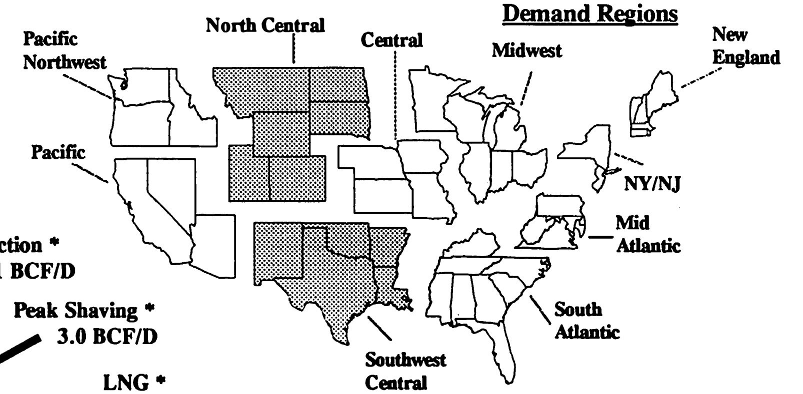


U. S. Delivery Capability Calculation

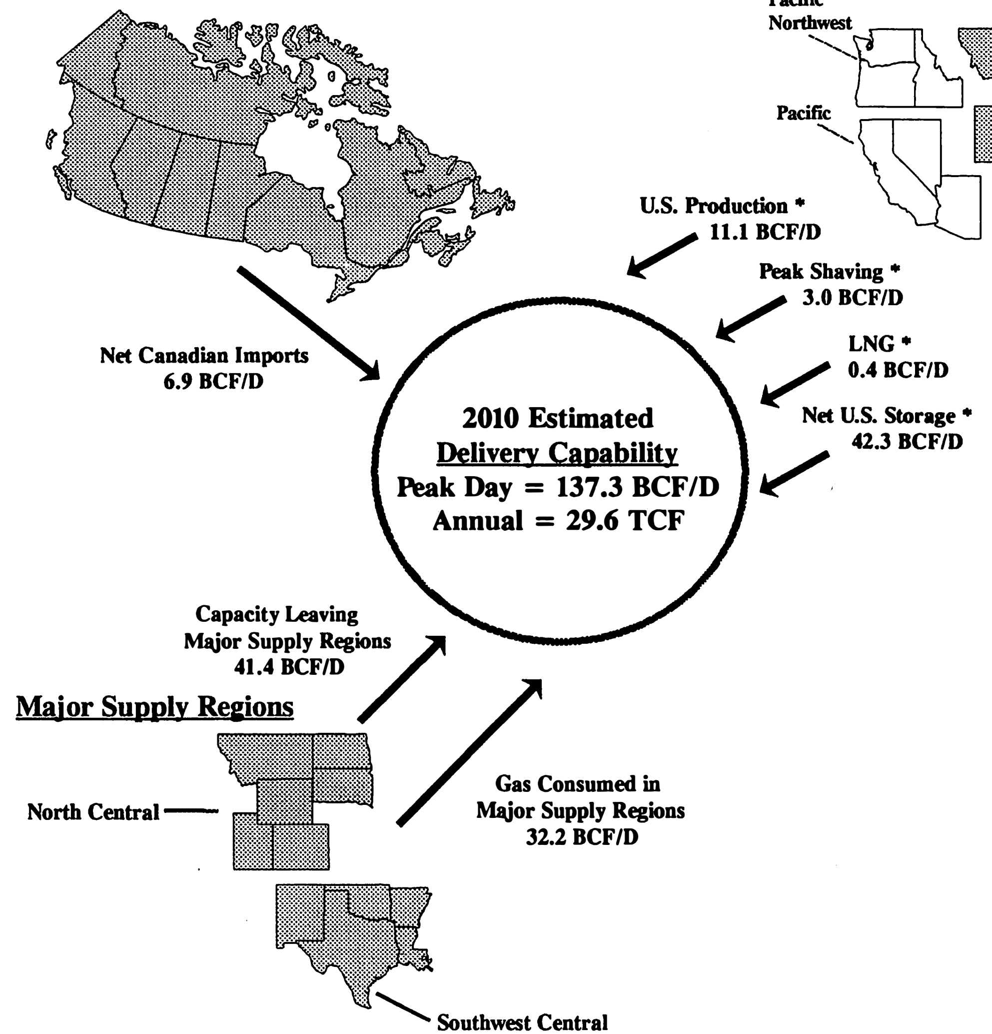
	Peak Day (BCF/D)	Annual (TCF)
Leaving/Consumed in Major Supply Regions		
Capacity Leaving SW Central Region (1)	33.8	11.7
Capacity Leaving N. Central Region (1)	3.9	1.4
Gas Consumed in SW Central Region	26.1	7.3
Gas Consumed in N. Central Region	5.7	1.1
Net SW Central / N. Central Capacity	69.5	21.5
Canadian Imports		
Capacity from All of Canada (1)	9.9	3.4
Less Canadian import to N. Central	(2.5)	(0.9)
Less Re-exports to Canada (1)	(1.6)	(0.5)
Net Canadian Imports	5.8	2.0
Demand Region Deliverability		
Total U. S. Storage Withdrawal	53.7	0.0
Less SW Central and N. Central	(12.0)	0.0
Net U. S. Storage (2)	41.7	0.0
U. S. Production (3)	10.5	4.4
Peak Shaving (3)	3.0	0.0
LNG (3)	0.4	0.1
Grand Total	**130.9**	**28.0**

(1) Annual volume assumes peak day capacity at 95% load factor
(2) Assumed no contribution from storage on an annual basis
(3) Less Contributions from SW Central & N. Central

Figure 3-6.
2010 Estimated U.S. Capability to Deliver Natural Gas
(Based on NPC High Reference Case)



*Note: Excludes deliveries from SW Central and N. Central Regions



U. S. Delivery Capability Calculation

	Peak Day (BCF/D	Annual (TCF)
Leaving/Consumed in Major Supply Regions		
Capacity Leaving SW Central Region (1)	33.8	11.7
Capacity Leaving N. Central Region (1)	7.6	2.6
Gas Consumed in SW Central Region	26.0	7.4
Gas Consumed in N. Central Region	6.2	1.2
Net SW Central / N. Central Capacity	73.6	22.9
Canadian Imports		
Capacity from All of Canada (1)	11.5	4.0
Less Canadian import to N. Central	(2.9)	(1.0)
Less Re-exports to Canada (1)	(1.7)	(0.6)
Net Canadian Imports	6.9	2.4
Demand Region Deliverability		
Total U. S. Storage Withdrawal	54.5	0.0
Less SW Central and N. Central	(12.2)	0.0
Net U. S. Storage (2)	42.3	0.0
U. S. Production (3)	11.1	4.2
Peak Shaving (3)	3.0	0.0
LNG (3)	0.4	0.1
Grand Total	**137.3**	**29.6**

(1) Annual volume assumes peak day capacity at 95% load factor
(2) Assumed no contribution from storage on an annual basis
(3) Less Contributions from SW Central & N. Central

NATIONAL PETROLEUM COUNCIL
SUMMARY OF ESTIMATED U.S. CAPABILITY TO DELIVER NATURAL GAS
(NPC High Reference Cases)

Leaving/Consumed in Supply region	1988*		1991		1995		2000		2005		2010	
	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)
Capacity from SW Central (#6)												
To South Atlantic (#4,IC+ID)	7,920	-	19,466	-	19,566	-	19,566	-	19,566	-	19,566	-
To Central (#7, II)	20,385	-	9,192	-	9,192	-	9,192	-	9,192	-	9,192	-
To Pacific (#9, V)	4,660	-	4,319	-	5,065	-	5,065	-	5,065	-	5,065	-
less Mexican imports	-		0	-	0	-	0	-	0	-	0	
TOTAL	32,965	11,431	32,977	11,435	33,823	11,728	33,823	11,728	33,823	11,728	33,823	11,728
Consumed in SW Central (#6, IIIA+IIIB)	25,923	6,391	23,325	6,593	24,958	6,807	25,604	7,118	26,069	7,307	25,999	7,372
Capacity from N. Central (#8, IV)												
To Midwest (#5, II)	1,450	-	1,363	-	1,676	-	1,676	-	1,776	-	3,592	-
To Central (#7, II)	-	-	1,040	-	1,040	-	1,040	-	1,102	-	2,229	-
To Pacific (#9, V)	120	-	0	-	700	-	700	-	742	-	1,501	-
To Pacific N.W. (#10,-)	-	-	324	-	324	-	324	-	324	-	324	
TOTAL	1,570	544	2,727	946	3,740	1,297	3,740	1,297	3,944	1,368	7,646	2,651
Consumed in N Central (#8, IV)	3,549	613	4,428	927	4,885	738	5,263	938	5,687	1,069	6,156	1,184
SUBTOTAL SW & N. CENTRAL CAP.	64,007	18,979	63,457	19,900	67,406	20,570	68,430	21,081	69,523	21,472	73,624	22,935
Canadian Imports												
From all of Canada	4,592	1,593	6,457	2,239	8,746	3,033	9,575	3,320	9,860	3,419	11,485	3,982
less Canadian import to N. Central	(1,110)	(385)	(1,225)	(425)	(1,780)	(617)	(2,478)	(859)	(2,478)	(859)	(2,879)	(998)
Re-exported to Canada	(975)	(338)	(1,012)	(351)	(1,516)	(526)	(1,555)	(539)	(1,587)	(550)	(1,665)	(577)
Net imports from Canada	2,507	870	4,220	1,463	5,450	1,890	5,542	1,922	5,795	2,009	6,941	2,407
U.S. Storage Capability	52,356	-	53,655	-	53,655	-	53,655	-	53,655	-	54,524	-
Less: SE Central	(13,675)	-	(10,058)	-	(10,058)	-	(10,058)	-	(10,058)	-	(10,416)	-
N Central	(1,693)	-	(1,870)	-	(1,870)	-	(1,870)	-	(1,870)	-	(1,870)	-
Net Storage Capability	36,988		41,727		41,727		41,727		41,727		42,238	
U.S. Production	44,477	18,038	55,731	21,570	51,925	20,037	53,195	20,488	55,904	21,519	55,988	21,499
Less: SE Central	(39,019)	(15,825)	(43,431)	(16,954)	(36,720)	(14,334)	(35,239)	(13,756)	(36,385)	(13,848)	(33,304)	(13,001)
N Central	(2,294)	(930)	(5,319)	(1,991)	(6,974)	(2,611)	(8,091)	(3,029)	(8,985)	(3,280)	(11,553)	(4,325)
Net U.S. Production	3,164	1,283	6,981	2,625	8,231	3,092	9,865	3,703	10,534	4,391	11,131	4,173
Peak Shaving	7,778	-	2,998	-	2,998	-	2,998	-	2,998	-	2,998	-
Less: SE Central	(383)	-	(16)	-	(16)	-	(16)	-	(16)	-	(16)	-
N Central	(109)	-	(8)	-	(8)	-	(8)	-	(8)	-	(8)	-
Net Peak Shaving	7,286		2,974		2,974		2,974		2,974		2,974	
LNG	137	50	980	307	1,060	334	1,060	334	1,060	334	1,060	334
Less: SE Central	-	-	(700)	(219)	(700)	(219)	(700)	(219)	(700)	(219)	(700)	(219)
Net LNG	137	50	280	88	360	115	360	115	360	115	360	115
GRAND TOTAL	114,089	21,182	119,639	24,077	126,148	25,667	128,898	26,821	130,913	27,987	137,268	29,630

* Estimated based on the 1989 NPC Petroleum Storage & Transportation Report (Appendix H, pg 9)

NATIONAL PETROLEUM COUNCIL
SUMMARY OF ESTIMATED U.S. CAPABILITY TO DELIVER NATURAL GAS
(NPC Low Reference Cases)

Leaving/Consumed in Supply region	1988*		1991		1995		2000		2005		2010	
	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)	PK DAY (MMCF/D)	ANNUAL (BCF/D)
Capacity from S W Central (#6)												
To South Atlantic (#4,IC+ID)	7,920	-	19,566	-	19,566	-	19,566	-	19,566	-	19,566	-
To Central (#7, II)	20,385	-	9,192	-	9,192	-	9,192	-	9,192	-	9,192	-
To Pacific (#9, V)	4,660	-	4,319	-	5,065	-	5,065	-	5,065	-	5,065	-
less Mexican imports	-		0	-	0	-	0	-	0	-	0	
TOTAL	32,965	11,431	33,077	11,469	33,823	11,728	33,823	11,728	33,823	11,728	33,823	11,728
Consumed in SW Central (#6, IIIA+IIIB)	25,923	6,391	23,340	6,388	23,634	6,474	22,868	6,239	23,547	6,612	23,183	6,620
Capacity from N. Central (#8, IV)												
To Midwest (#5, II)	1,450	-	1,363	-	1,676	-	1,676	-	1,676	-	2,132	-
To Central (#7, II)	-	-	1,040	-	1,040	-	1,040	-	1,040	-	1,323	-
To Pacific (#9, V)	120	-	0	-	700	-	700	-	70	-	891	-
To Pacific N.W. (#10,-)	-	-	324	-	324	-	324	-	324	-	324	
TOTAL	1,570	544	2,727	946	3,740	1,297	3,740	1,297	3,110	1,078	4,670	1,619
Consumed in N Central (#8, IV)	3,549	613	4,430	612	4,609	712	4,759	840	5,017	938	5,157	990
SUBTOTAL SW & N. CENTRAL CAP.	64,007	18,979	63,574	19,415	65,806	20,211	65,190	20,104	65,497	20,357	66,833	20,957
Canadian Imports												
From all of Canada	4,592	1,593	6,827	2,367	8,823	3,059	9,598	3,328	9,598	3,328	10,742	3,725
less Canadian import to N. Central	(1,110)	(385)	(1,225)	(425)	(1,780)	(617)	(2,555)	(886)	(2,555)	(886)	(3,125)	(1,084)
Re-exported to Canada	(975)	(338)	(1,012)	(351)	(1,516)	(526)	(1,555)	(539)	(1,587)	(550)	(1,665)	(577)
Net imports from Canada	2,507	870	4,590	1,592	5,527	1,916	5,488	1,903	5,456	1,892	5,952	2,064
U.S. Storage Capability	52,356	-	53,655	-	53,655	-	53,655	-	53,655	-	53,655	-
Less: SE Central	(13,675)	-	(10,058)	-	(10,058)	-	(10,058)	-	(10,058)	-	(1,058)	-
N Central	(1,693)	-	(1,870)	-	(1,870)	-	(1,870)	-	(1,870)	-	(1,870)	-
Net Storage Capability	36,988		41,727		41,727		41,727		41,727		50,727	
U.S. Production	44,477	18,038	55,608	21,570	50,041	19,310	46,000	17,735	48,585	18,683	47,660	18,310
Less: SE Central	(39,019)	(15,825)	(43,281)	(16,954)	(35,368)	(13,806)	(29,796)	(11,632)	(30,429)	(11,879)	(28,858)	(13,001)
N Central	(2,294)	(930)	(5,356)	(1,991)	(6,530)	(2,445)	(7,387)	(2,766)	(8,244)	(3,086)	(8,961)	(3,355)
Net U.S. Production	3,164	1,283	6,971	2,625	8,143	3,059	8,817	3,337	9,912	3,718	9,841	1,954
Peak Shaving	7,778	-	2,998	-	2,998	-	2,998	-	2,998	-	2,998	-
Less: SE Central	(383)	-	(16)	-	(16)	-	(16)	-	(16)	-	(16)	-
N Central	(109)	-	(8)	-	(8)	-	(8)	-	(8)	-	(8)	-
Net Peak Shaving	7,286		2,974		2,974		2,974		2,974		2,974	
LNG	137	50	980	307	1,060	334	1,060	334	1,060	334	1,060	334
Less: SE Central	-	-	(700)	(219)	(700)	(219)	(700)	(219)	(700)	(219)	(700)	(219)
Net LNG	137	50	280	88	360	115	360	115	360	115	360	115
GRAND TOTAL	114,089	21,182	120,116	23,720	124,537	25,301	124,556	25,459	125,926	26,081	136,687	25,090

* Estimated based on the 1989 NPC Petroleum Storage & Transportation Report (Appendix H, pg 9)

APPENDIX G

FERC OFFICE OF ECONOMIC POLICY REPORT ON "IMPORTANCE OF MARKET CENTERS"

IMPORTANCE OF MARKET CENTERS

Federal Energy Regulatory Commission

Office of Economic Policy

Washington, DC
August 21, 1991

This is an OEP discussion paper. It does not necessarily represent the views of the Commission, any individual Commissioner, the Commission staff, or any individual member of the Commission staff.

TABLE OF CONTENTS

IMPORTANCE OF MARKET CENTERS

Office of Economic Policy
August 21, 1991

SUMMARY

Since the NGPA in 1978, Congress and the Commission have worked to foster a more flexible wellhead market for natural gas.

The interstate pipeline grid includes areas where several pipelines come together near large production or storage fields (see Figure 1). These are natural market centers where many gas buyers and sellers can come together (see Figure 2 for the pipelines within a typical market center).

Such centers can improve markets by cutting transactions costs, increasing reliability and giving buyers and sellers more options. Producers will less often have to accept lower prices because they can't get to a potential buyer. Buyers need seldom pay more because they can't get to the most competitive producers.

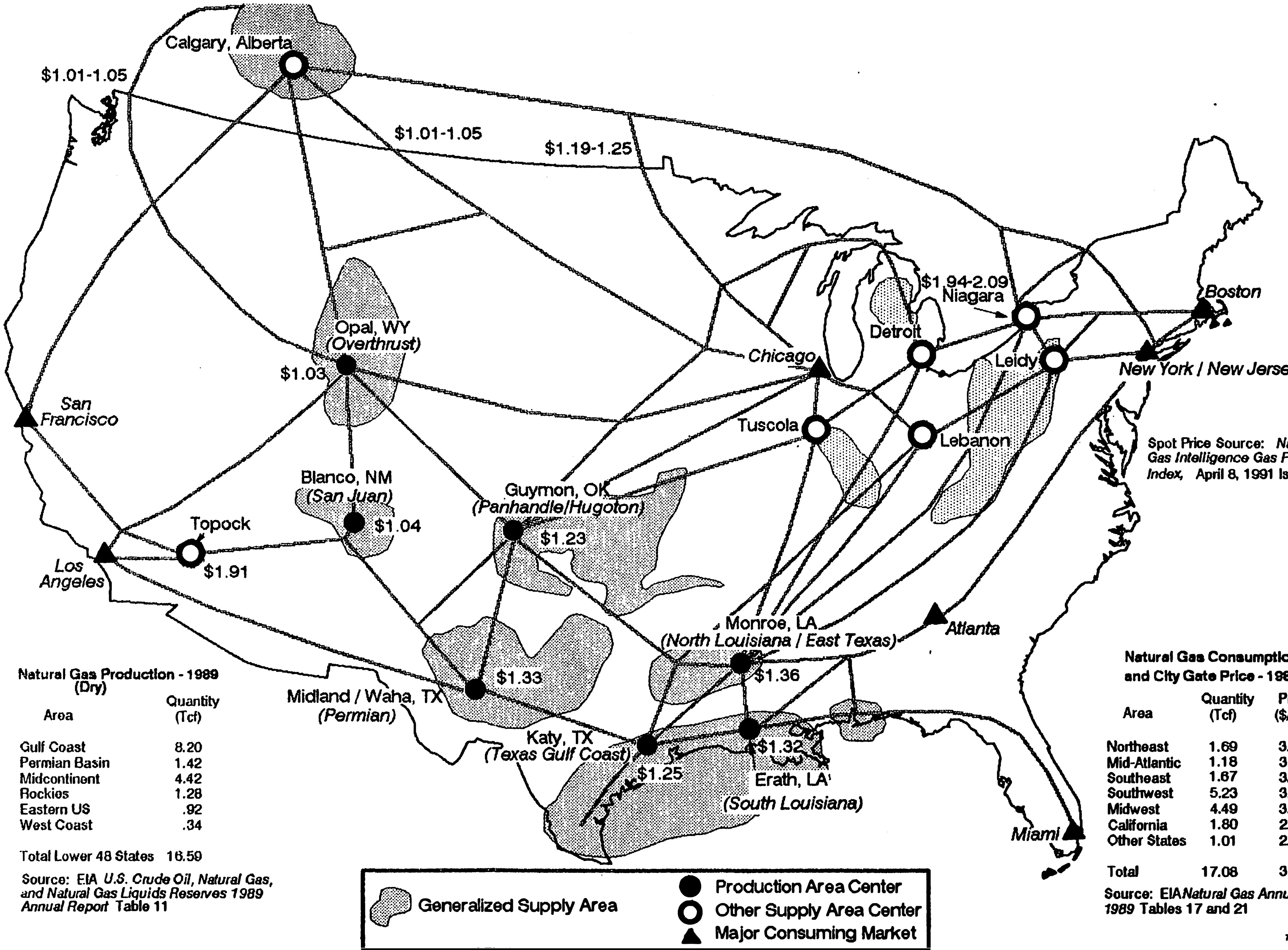
Market centers also offer natural aggregation points for many gas buyers and sellers where the market power of pipelines could be quite low. This would make it much easier for all market participants to compete on even terms and for small buyers and producers to do business.

Some pipelines are starting market centers of their own. The Commission could spur further efficiencies if it:

- o recognizes natural market centers
- o prompts pipelines to accommodate rates to reflect market centers
- o simplifies receipt point complications by offering producers the rights to capacity into production area market centers
- o increases access and reliability in downstream market centers.

Market centers would require only small transition costs. They might also lower the transition costs of unbundling. Pipelines could restructure existing capacity rights and long-term contracts more easily.

FIGURE 1.
Market Center/Pooling Areas for Major Pipeline Routes



Spot Price Source: *Natural Gas Intelligence Gas Price Index*, April 8, 1991 Issue

Natural Gas Production - 1989 (Dry)

Area	Quantity (Tcf)
Gulf Coast	8.20
Permian Basin	1.42
Midcontinent	4.42
Rockies	1.28
Eastern US	.92
West Coast	.34
Total Lower 48 States	16.59

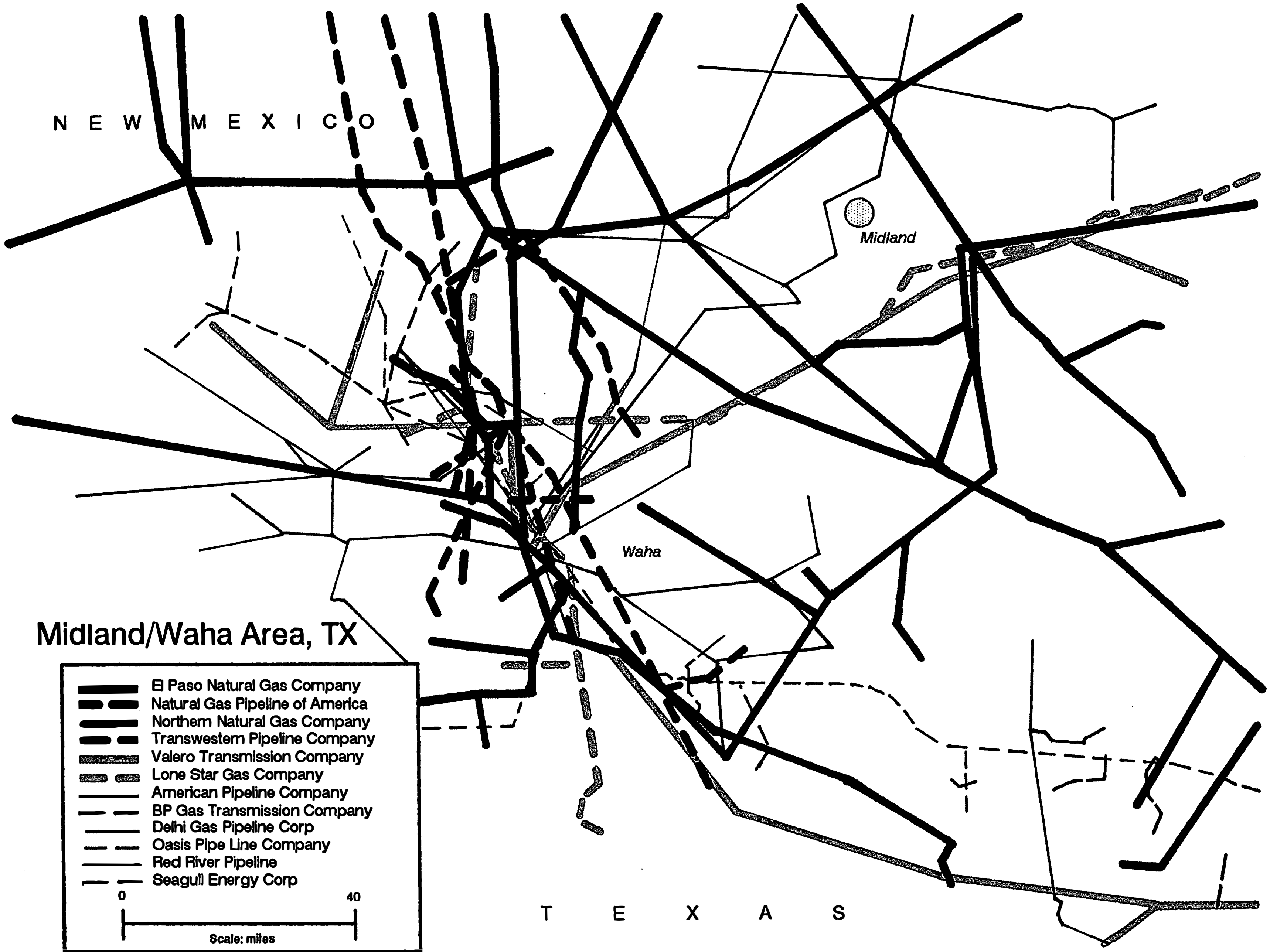
Source: EIA *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1989 Annual Report* Table 11

Natural Gas Consumption and City Gate Price - 1989

Area	Quantity (Tcf)	Price ($/Mcf)
Northeast	1.69	3.15
Mid-Atlantic	1.18	3.26
Southeast	1.67	3.05
Southwest	5.23	3.09
Midwest	4.49	3.07
California	1.80	2.75
Other States	1.01	2.33
Total	17.08	3.02

Source: EIA *Natural Gas Annual 1989* Tables 17 and 21

7-15-91



NOTE: This map was re-drawn from a color original furnished by the Federal Energy Regulatory Commission (pipeline route map copyright 1991 Petroleum Information Corporation).

7-22-91

IMPORTANCE OF MARKET CENTERS

INTRODUCTION

Since the NGPA, national and Commission policy has been to break down barriers to competition in the natural gas industry. Most policy initiatives have focused on legal and regulatory reform. But many other practical barriers to trade remain from an era of wellhead-to-burner-tip regulation in fragmented markets.

The NGPA recognized the merits of competition over regulation for wellhead gas supplies, set up a schedule to deregulate new gas and created access to previously unavailable supplies.

Order No. 380 removed minimum bills from pipeline tariffs. Buyers gained more choice among gas suppliers.

Orders No. 436 and 500 opened access to pipeline transportation, giving more access to buyers and sellers.

The Wellhead Decontrol Act extended the categories of gas not subject to Federal regulation. It deregulates all gas by January 1, 1993.

The Administration's National Energy Strategy would increase competition in the industry and enhance the role of gas in the nation's overall energy mix.

The new construction rule may (among other things) lower barriers to construction further and increase competition for new services.

Despite fits and starts, the transition has made the gas industry far more competitive than it was in 1978. But decades of strong regulation left many other barriers to full and fair competition that are as much a matter of custom as of regulation. Without further reform, deregulated commodity markets will be coupled to needlessly Balkanized transportation markets.

Buyers and sellers still face several barriers to deals that might otherwise make sense. These include:

- receipt point inflexibility or delays in changing receipt points. This can prevent shippers from buying attractively priced gas. Individual pipeline customers depend on specific receipt points for long-term firm supplies.
- limited responses to supply disruption. A shipper facing a supply disruption may only look for replacement suppliers at its current receipt points. This lowers reliability.
- the difficulty of reselling long-term contracted gas.
- the lack of institutions to help buyers and sellers find each other and do business. A buyer-and-seller-find-each-other approach to gas contracting is wasteful. Most commodity markets have clearing authorities to match parties, market centers and "paper" transactions to cut transaction costs.

Together, these barriers may reduce the practical options open to gas buyers and sellers. The lack of flexibility prevents competition from working fully and makes contingency planning harder. That in turn prevents the Nation from realizing many efficiencies that competition should produce.

Market centers can lower these barriers to trade and reliability. They can thus increase competition and efficiency and cut needless costs. They would help fulfil the Congressional intent that:

> *all sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other suppliers.* (H. R. Rep. No. 29, 101st Cong., 1st Sess., at p.6 (1989))

WHAT ARE MARKET CENTERS?

Market centers are places where many sellers and buyers can make or take delivery. The idea is not new. Buyers and sellers in ancient Greece gathered in great open air markets called agoras. Fish and farmers markets have thrived in natural centers (towns or piers) near the production area. In New Mexico, the Pecos National Monument served as a natural market center.

Today, the idea is well developed in most industries -- for instance, agriculture, minerals, art, finished goods and financial instruments. Forcing people to buy and sell natural gas at many different places may in some instances raise transaction costs and lessen reliability.[1]

The gas industry has physical constraints to receipt and delivery. So market centers must cover areas where several pipelines come together. These would become hubs where many suppliers could deliver gas and many buyers could take delivery. The gas futures contract -- with physical delivery as a backstop -- chose the Henry Hub (near Erath, LA) as the reference exchange point.

Many potential market centers are near production areas. They are ideal places for producers to sell gas to downstream customers. Others (for instance, the Leidy, Pennsylvania area) are near downstream storage fields. These market centers promote trades among downstream customers.

The defining features of a market center are:

- **many buyers and sellers** can make and take delivery. This prevents the exercise of market power and maximizes the chances of making efficient trades. So, market centers must be near the intersection of several pipelines. For convenience and balancing, they should also be near fairly large production or storage areas.

- **a hub manager** can match buyers and sellers physically. Gas may be displaced through several pipelines within the hub to reach the buyer. The hub manager -- perhaps a group of pipelines using real-time information and control systems -- would arrange the transaction. The transportation tariff for the service would stay under Commission jurisdiction.

A clearing-house may develop to match buyers and sellers. It might also quote prices, buy and sell imbalances or set up standard ways to resolve disputes.

Trades at market centers would usually involve three parties: buyer, seller and hub manager. Some could also include a clearing-house, depending on the specific transaction. The simplest trades would involve a buyer and seller who agree to exchange title to the gas at the market center on a single pipeline.

A more complex transaction would involve a buyer and seller who are matched by the clearing-house, with the gas entering and exiting the market center on different pipelines and intra-hub transportation (perhaps on several pipelines) arranged by the hub manager.

WHERE ARE NATURAL MARKET CENTERS?

The pipeline grid contains many natural market centers -- see Figure 1. A market center includes a central point and a concentric area to include pipelines that connect nearby -- see Figure 2 for the pipeline configuration at a sample market center. We included three types of pipelines within the market centers:

- o *principal pipelines* -- those that connect at a center point like a gas plant

- o *beltway pipelines* that connect near the center (usually within 70 miles)

Table 1 shows the center and concentric area of each center, its storage capacity and how many pipelines connect nearby. Attachment A (available on request) contains maps of each market center.

COMPETITION AT MARKET CENTERS IN PRODUCTION AREAS

Market centers would make it much easier to be sure that pipelines compete in buying and selling gas on equal terms with all others.

The Commission has been concerned that pipelines might control enough gas supplies in specific areas and access to key transportation services that they could exercise market power as sellers. The most important product that gas suppliers could sell at market centers would probably be long-term firm gas, especially for delivery during peak periods. Analysis of production areas that could serve market centers in production areas shows considerable competition. (See Appendix A.)

The most concentrated production area market centers are Blanco, NM and Katy, TX -- see HHIs on Table 1. (The HHI measures concentration by squaring the market shares of each company. For example, a market divided equally between two firms has an HHI of .5.)

Blanco has the equivalent of 5.7 equally large uncommitted and pipeline suppliers. It appears to be the most concentrated potential market center and might need more study. But with appropriate access, sellers in most production area centers are unconcentrated. Guymon, OK has the same HHI as a market with over 30 equally large sellers. It is almost inconceivable that a pipeline could use its control of gas supply to exert market power in such a case. (Comparable transportation is still essential -- otherwise, a pipeline could exercise market power through control not of supplies but of the pipeline itself.)

Table 1: MARKET CENTER INFORMATION

Market Center	No. of Pipelines	Center Point	Radius (miles)	Production Deliverability (Bcf/d)	Peak Storage Deliverability (Bcf/d)[c]	HHI[d]
Blanco, NM	3	Blanco Gas Plant	120[a]	2.45		0.1774
Detroit, MI	6	Pipeline connection	65		3.30	
Erath, LA	28	Henry Gas Plant	50	19.15		0.0643
Guymon, OK	16	Pipeline connection	65	12.05	0.45	0.0327
Katy, TX	23	Katy Gas Plant	70	12.02	2.75	0.1691
Lebanon, OH	6	Pipeline connection	60			
Leidy, PA	6	Pipeline connection	30		5.10	
Midland/Waha, TX	15	Waha Gas Plant	70	5.29		0.0959
Monroe, LA	14	Pipeline connection	50	2.74	0.96	0.0938
Niagara, NY	6	Pipeline connection	50		0.41	
Opal, WY	12	Pipeline connection	110[b]	2.90	0.32	0.0811
Topock, AZ	5	Pipeline connection	10			
Tuscola, IL	5	Pipeline connection	45		0.10	

a If new facilities were built to connect El Paso and Transwestern pipelines, the distance between the center point and the new interconnection could be reduced to about 90 miles.

b If a pipeline interconnection near Rock Springs (rather than Opal) were the center point, the radius could be reduced to about 75 miles.

c Total reserves divided by annual reserve to deliverability ratio divided by 365.

d HHI for uncommitted and pipeline supplies.

Market centers can also play a key role outside production areas. Downstream market centers are usually near both major consumption markets and the intersection of several major pipelines. They also normally have high storage capacity. Downstream centers can serve as transshipment or aggregation points for several production area centers. Their storage capacity can provide important balancing and supply during peak periods. During a cold spell, a spot market at downstream centers may add flexibility to the system and prevent some supply curtailments.

HOW DO MARKET CENTERS HELP?

Market centers can reduce barriers to a more efficient market because they can:

- **cut transactions costs**. Today's way of matching buyers and sellers can improve.
- **make pricing information available more widely**. Such *price discovery* is essential to efficient commodity markets.
- **reduce institutional constraints**. Constraints like receipt and delivery point inflexibility can prevent gas sales and impair reliability. A better way of allocating capacity rights could make the system more flexible and cut costs.
- **increase the benefits of intermediation and diversification**. Gas merchants can lower costs by aggregating and matching their customers' different load profiles (the peak of the sum is less than the sum of the peaks) and production schedules.

These ideas are neither new nor untested. Most established, efficient markets have eliminated needless barriers to trade (think of stock and commodity exchanges). Central, common trading areas with quoted prices and low transactions costs make trading easier. Several limited market centers have already developed in the natural gas industry without direct Commission intervention.

WHAT CAN THE COMMISSION DO?

The Commission could help further by acting to:

- identify principal market centers
- structure rates
- set rights to transportation to and from market centers.

Identify market centers. The Commission could intervene and encourage the organization of market centers where several pipelines meet. Otherwise, pipelines may set up market centers only on their own systems.

Structure rates. The Commission could require pipelines to post separate, unbundled rates:

- to deliver gas into the market center.
- to deliver gas from the market center to downstream delivery points.
- to deliver gas between market centers
- to deliver gas within a market center

Set transportation rights to and from market centers. The Commission could require pipelines entering and leaving a market center to split existing capacity rights into wellhead-to-market-center rights and market-center-to-city-gate rights. Pipelines might then charge zone rates with boundaries at the market centers.

Producers often must use specific upstream facilities and thus are likely to place a higher value on them than buyers. For a buyer, having firm rights to specific production area receipt points may merely constrain its choice of gas suppliers. And producers would do far better with capacity to market centers only -- that way they could reach far more buyers.

Capacity release programs also would benefit from market centers. For a downstream customer, for instance, the capacity would come only out of the market center. It would not force the new capacity holder to deal with unwanted receipt or delivery points or the burden of reassignment.

TRANSITION

Market centers need cause almost no disruption in the industry. Some limited market centers are developing naturally without Commission intervention or encouragement. They normally impose few or no extra constraints on shippers. Rather they offer customers more options.

Almost all the activities that could occur at a market center already take place. Buyers and sellers seek each other out, and both search for practical ways to move their gas. But there would be some changes.

More buyers and sellers would have access to each other. This will probably mean more potential trades with lower transaction costs.

There would be a standard way to get gas from sellers on one pipeline to buyers on another. This would require coordination among pipelines -- they are doing similar things to accommodate gas exchanges. Telecommunications and computer upgrades could focus on market centers and lower costs.

Rights to firm pipeline capacity would change. Market centers provide a simple way to modify existing transactions.

The pipeline would offer these rights using a priority that promises a fair, natural and low-cost transition from current practice. The priority should disrupt ongoing transactions as little as possible and minimize transaction costs. That implies that the pipeline offer rights into the market center in the following order:

1. producers with system supply contracts
2. other producers behind the system
3. other existing customers
4. all others.

It would offer rights out of the market center in the following order:

1. existing firm customers
2. existing customers of firm customers
3. other existing customers
4. all others.

Those who accept the rights may assign them later through a capacity releasing program.

This approach would cut transportation-related barriers to trade. It would also make the receipt and delivery point issues the Commission now faces much less complicated.

CONCLUSION

Market centers offer many potential benefits to the natural gas industry. They can:

- increase the opportunities and flexibility available to all buyers and sellers
- make transactions easier -- for example, by simplifying receipt and delivery point problems.
- let many parties aggregate supplies as pipelines have traditionally done.
- greatly reduce the market power of pipelines as gas suppliers. Pipelines would compete more fairly with other gas suppliers and aggregators -- see Appendix A.
- reduce any artificial barriers to long-term contracts inherent in the current system. Sellers or buyers could (if they wished) rely on the spot market at the market center to support their long-term contracts without fear of transportation rigidities or temporary supply shortfalls.
- foster an environment that allows long-term contracts. Both producers and customers could enter the long-term deals that make the most commercial sense. That is, parties could make long-term deals to share risk as they wish, not just to make transportation arrangements work.
- reduce the bilateral monopoly nature of many current industry transactions.
- focus the upgrade of real-time communications links, thereby lowering costs.

DOE/FE-0258P

Appendix H

FERC/DOE Natural Gas Deliverability Task Force Report

Chapter 1

Delivery of Natural Gas in the United States:

Is the Data Reliable?

A Joint FERC/DOE Project

September 1992

CHAPTER 1

BACKGROUND AND CONCLUSIONS

1.1 INTRODUCTION

Implementation of the Natural Gas Policy Act of 1978 ("NGPA") resulted in market forces which, in combination with regulatory responses to these forces, increased the competitiveness of natural gas markets in the United States. Initially, the major impact of these changes was felt in the wellhead production market. Since 1982, however, major changes have affected downstream markets as well.

Most gas sold at the wellhead has effectively become price decontrolled and, consequently, spot market transactions have become commonplace. Marketers have assumed a greater role as intermediates between producers on the one hand, and distributors and large end users on the other. These developments created a need for pipeline companies to separate, or unbundle, their transportation services from the package of services they traditionally provided as merchants selling gas. Restructuring of the traditional system for marketing gas from the wellhead to the consumer facilitated still further participation in new transportation programs and in the emerging spot market.

With the implementation of interstate open access by the Federal Energy Regulatory Commission ("FERC" or "the Commission"), and with adjustments in state guidelines regulating intrastate pipeline and local distribution companies ("LDCs"), large quantities of gas now flow independently of the supplies used by traditional transporters and distributors of natural gas.

The ultimate success of the evolving competitive natural gas market depends largely on the quality of signals exchanged by the participants. Without good information on deliverability, those signals can be only partially accurate. In addition, without timely deliverability data, business and government leaders could make flawed decisions based on unreliable information, resulting in skewed economic consequences.

Information on natural gas today is often fragmentary, late, and focused on outdated issues. Redesigning data systems to serve the emerging, competitive natural gas industry is a crucial challenge for the next decade. The information infrastructure that now serves the natural gas industry was built for the industry of the 1950s, 1960s, and 1970s. Vast changes in the world energy markets, along with the recent overhaul of regulatory theory and practice, have instigated relatively swift changes in market roles and structures.

Key elements of the information infrastructure change will include:

- Refocusing much of the information to serve those who buy and sell both natural gas and pipeline capacity. This means a major shift away from the information needed for traditional regulation;

- Receiving crucial information much faster and tying the information to market institutions where parties actually buy and sell gas or capacity. This implies that Electronic Bulletin Boards ("EBBs") should be attached to market centers to allow as many buyers and sellers as possible to access information; and

- Retooling other information to serve the needs of regulatory monitoring rather than heavy-handed intervention.

Information will be the life-blood of emerging and rapidly changing competitive gas markets. In such an environment, parties currently have little experience on which to base their decisions. They will depend far more on information sources than do many participants in older markets.

1.2 OBJECTIVES

The purpose of this study was threefold: (1) to review current deliverability data for utility, accuracy, and timeliness; (2) to identify mechanisms for closing significant gaps in information resulting from changing market structures; and (3) to ensure that technologies are available to meet the needs of the emerging, competitive natural gas industry.

This report is the result of a joint effort between the U.S. Department of Energy ("DOE") and FERC to analyze natural gas deliverability. This effort, initiated in 1990, was undertaken by a Deliverability Task Force ("DTF"). Primary objectives of the DTF were as follows:

- Assess the accuracy and utility of currently available information on deliverability;
- Recommend initiatives at the state and federal levels, if needed, to increase the credibility and timeliness of information now being used to measure deliverability;
- Provide leadership on the national level by illuminating the importance of natural gas deliverability as an indicator in the nation's energy markets; and
- Encourage, not mandate, the development of accurate, reliable, current deliverability information.

By assessing the nation's ability to deliver natural gas from the wellhead to the burner tip, the findings would provide a major contribution to the information base being compiled for use in the National Energy Strategy Project.

The DTF's work consisted of studying deliverability data through a case study of existing data and a series of assessments by three panels: Industry Panel, Technical Panel, and Regulatory Panel. The case study was performed for the State of Oklahoma, a major natural gas producing state. The panels independently investigated three areas of concern and attempted to seek answers to specific questions regarding each area: Definition and Terminology, Assessment of Existing Information, and Ways to Improve the System.

1.3 CONCLUSIONS

A. Oklahoma Test Case

The Oklahoma Test Case results highlighted how difficult it is to find accurate, timely data on natural gas flows:

- Receiving timely, accurate deliverability data is very difficult, even with intense cooperation by a federal-state-private task force.
- No single data source supplies all the basic information on Oklahoma natural gas markets. The problem is worse for those who conduct business transactions in several states.
- Time lags could reach a year for calculating a reasonable material balance from existing information on the production, transportation, and consumption of natural gas in Oklahoma.

B. Panels

The three panel approach worked well because observations and conclusions were developed by the actual compilers and users of deliverability information, not by federal policy makers. In addition, by requiring each panel to work independently, unique panel viewpoints offer an internal check and balance mechanism to the recommendations included in this final report.

All three panels were generally consistent in surveying certain sources of information on natural gas. In addition, all three panels commented on similar deficiencies in the accuracy, utility, reliability, and timing of existing reporting on deliverability.

Each of the panels concluded to varying degrees that the current collection and reporting system for deliverability information is outmoded, unreliable, and in need of improvement. It is apparent that each panel formed its own unique opinions and conclusions concerning how best to modernize and otherwise improve upon the nation's system of reporting data on natural gas flows.

All panels agreed on the perceived value of bringing the current reporting regimes into the modern age of electronic reporting. Computerization of even the currently available information would greatly enhance its timeliness and utility to market participants.

C. FERC/DOE Deliverability Task Force

The Task Force agrees with the panels that vital information about the capacity and performance of the natural gas delivery system in the United States is simply not available in a form that is accurate, reliable, or timely enough to add maximum benefits to the nation's competitive natural gas markets.

A system of natural gas data must be developed to meet the needs of tomorrow's markets. In these markets, "All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other suppliers." (House Committee Report to the Natural Gas Wellhead Decontrol Act of 1989.)

To make this vision a reality, buyers and sellers need timely data that includes:

- The quantity of natural gas that can be delivered from wellhead supply or from the storage site;
- Receipt points on the pipeline grid where natural gas supplies from storage or a wellhead can enter the grid;
- The alternative transportation paths from points of receipt to points of delivery, including the available capacities on the pipeline(s) in the path; and
- The price and non-price terms associated with each alternative transportation path.

Current deliverability data does not provide this type of information in a timely fashion, and much of this information is not available at all. Sources of information designed for past transactions are in many cases not available in electronic format. The old forms, calculations, and estimations are often irrelevant to the task at hand in today's competitive world of gas marketing and delivery.

Even the existing data collection and reporting that is still relevant to today's industry is often inaccurate, hopelessly late, or both. Existing information that has remained useful is often fragmented and obscured in its meaning by virtue of its limitation to one reporting state, utility, or company.

The task force believes strongly that the entire nation can benefit if the current information system for reporting natural gas deliverability is modernized and tailored to fit the long-term needs of a competitive gas industry. Such a result can be achieved only through a cooperative and determined effort by all participants in the natural gas industry and government.

Clearly, no major segment of the energy industry can remain competitive or healthy for long without keeping abreast of changes in the information age. Therefore, it is necessary to build an information infrastructure that will grow in utility and sophistication at a pace equal to the ever changing natural gas industry. Better information permits better decisionmaking by business and government leaders alike.

More accurate information on the natural gas resource base and deliverability will reduce areas of uncertainty, a result that will be valuable to all participants evolving in the competitive marketplace. Hence, the consumer will be the ultimate beneficiary of a well functioning natural gas market that accurately reflects supply and demand characteristics.

Moreover, it has been suggested by some that the present information gap may seriously impair the ability of parties to make meaningful business decisions essential to restructuring services as contemplated by FERC Order No. 636 (the restructuring rule). Therefore, the timing of this report, with the issuance of the final Order No. 636, presents the industry and government with both the opportunity and the challenge to reform information systems that will guide competitive business and policy decisions well into the 21st Century.

The task force recognizes that many of its specific recommendations will require expenditures by federal and state governments, and private industry. Accordingly, each individual recommendation must be carefully studied from a cost-benefit analysis before it is implemented.

1.4 DTF RECOMMENDATIONS

The DTF commented on a variety of subjects relating to natural gas deliverability. These comments form the basis for the recommendations and conclusions drawn by FERC/DOE. The recommended improvements to deliverability data can be broadly grouped into four categories:

- Standardization of Information;
- Review, Development and Dissemination of Data;
- Implementation of Electronic Data Recording and Electronic Data Interchange ("EDI"); and
- Planning and Coordination for Peak Periods and Emergencies.

Although these recommendations are based entirely upon the findings and conclusions of the individual panels, specific recommendations are strictly those of FERC/DOE task force representatives. Both costs to the government and costs to industry and consumers should be considered in making decisions to proceed with data collection. The need to protect proprietary data must be respected. And the data must be collected in a manner that encourages private sector flexibility and innovation.

Panel recommendations are summarized in Table 1 at the end of this Chapter, and discussed below in detail. Individual panel reports are also included in this report as Appendices G, H, and I.

1. Standardization of Reporting: Production and Transportation Data

- Interstate Oil and Gas Compact Commission ("IOGCC") should work with the Energy Information Administration ("EIA"), Department of the Interior ("DOI") [Minerals Management Service ("MMS") and the Bureau of Land Management ("BLM")], and the producing states to examine the propriety and feasibility of developing a standard reporting regime for production data.

- DOE should consider the propriety of co-funding the development and installation of hardware and software in those states which are willing to participate in a cooperative effort to standardize the electronic reporting of gas production and deliverability data on a real-time basis to EIA.

- IOGCC should also work with producer organizations and states to improve the accuracy of reporting production data to the maximum extent practicable, consistent with the protection of proprietary information.

- Order No. 636 mandates the use of Electronic Bulletin Boards, but does not mandate uniform EBB standards for information content, display formats, and software. The FERC announced in Order No. 636-A that it would hold a technical conference in the near future in order to determine the progress made by the industry in developing interactive, user-friendly EBBs and uniform standards. In the event that industry has made insufficient progress by that time, FERC should consider standardizing the format, types of information, operation, and access to these EBBs.

2. Publications

- EIA should continue its annual report on natural gas reserves.

- In addition, EIA should use the three panel reports as a starting point and work with IOGCC and industry to develop a Natural Gas Deliverability Sourcebook and Glossary, to be published annually. This publication could help standardize terminology and provide a standard reference for sources of information on natural gas deliverability.

3. Storage and Supplemental Deliverability

- EIA should design and implement a system for compiling all storage and supplemental deliverability data [e.g., liquefied natural gas ("LNG"), propane air injection, and back-up oil supplies] into one easily accessed public electronic database.

- FERC and EIA should consider publishing on a regular basis storage data where doing so enhances the operation of the market, is cost-effective, and respects the need to protect proprietary data.

4. Gaps in Federal/State Reporting

- The National Association of Regulatory Utility Commissioners ("NARUC"), IOGCC and FERC should conduct a combined study of the gaps in reporting of natural gas deliverability information. This would include, but not be limited to, gathering capacities and flows, intrastate volumes, intrastate sales, and distributor sales. The study should make recommendations for improvements, standardization, and reporting of gaps in the national database.

5. Need for Existing or New Reporting

- Building upon the elimination of unneeded regulations already undertaken, the FERC should conduct an annual in-house evaluation of the need for continuing any existing reporting requirements.

- Upon completion of its analysis of reporting requirements, FERC should continue to eliminate unnecessary reporting and initiate a rulemaking for any necessary new reporting, with due consideration for the usefulness of the data, the value of the data in enhancing the workings of the market, the private and public cost of collecting it, and the protection of proprietary rights.

- FERC should analyze the internal costs, potential savings, and industry burdens associated with requiring substantially all pipeline reporting in standardized electronic format.

- EIA, DOI (MMS and BLM), the IOGCC and NARUC should join efforts to set up a mechanism for periodic review of the accuracy, timeliness, and utility of all government reporting on natural gas.

6. Real-Time Monitoring on the Grid

- The Secretary of Energy should consider tasking the National Petroleum Council ("NPC") to perform a study on how to improve the timeliness of reporting production data, including the propriety and cost of real-time telemetering of production data from states to a central collection point.

- In addition, the study should examine the feasibility and usefulness of establishing trunkline and/or hub telemetering points to provide instantaneous monitoring of regional flows of natural gas.

7. Need for EDI Standards

- The Secretary of Energy should consider tasking NPC to examine existing systems and recommend electronic data interchange standards for reporting natural gas deliverability data. In conjunction with EDI standards, the study should examine the propriety of adopting a standard set of facilities codes for the entire industry.

8. Need for Additional Electronic Communications

- FERC should consult with the Federal Communications Commission ("FCC") to consider the propriety of issuance of licenses to interstate pipelines and others for use in transmitting electronic data via secure microwave or other communication bands.

- FERC should evaluate all possible methods and technologies for improving electronic communications in the natural gas industry, including real-time data collection and exchange of deliverability data using local area networks, bulletin boards, microwave transmission systems, and related software.

9. Coordination During Emergencies

- NPC should conduct a conceptual and feasibility study on the structure and formation of a national voluntary organization to operate in times of emergency or extreme conditions such as those that developed during December, 1989. This coordination council would be composed of industry and government officials and would work to ensure good communications between all participants in the gas market during times of emergency and to ensure continued deliveries of natural gas to high-priority human needs customers. This council should consider appropriate agency and operational balancing agreements, negotiated pursuant to Order No. 636, which fully compensate non-essential use customers who yield supplies or capacity during emergencies.

10. Curtailment Conference: FERC and NARUC

- After the complete implementation of Order No. 636, FERC and NARUC should review the curtailment procedures adopted in the restructuring proceedings to ensure maximum coordination of procedures during any stressful period.

- The results of these reviews should be communicated to the coordination council described above for use in the management of emergency coordination procedures.

11. Correlation of Supply and Market Data

- NARUC, IOGCC and EIA should examine the data bases used by state public service commissions to determine if market data can be made compatible with production data bases compiled and reported in the producing states.

- In addition, NARUC should attempt to develop EDI standards for state reporting of demand data that are compatible with the EDI standards ultimately adopted by the natural gas industry.

12. Peak Day Demand

- After full implementation of Order No. 636, NARUC should ask each of its Public Utility Commission ("PUC") members to submit at regular intervals total peak day LDC demand data. That information could then be aggregated and published by NARUC so that the national peak day demand numbers would be available to the public on a timely basis.

- This important market information might be otherwise difficult to monitor as the trend continues under Order No. 636 toward conversion from pipeline sales service to pipeline transportation service.

13. Task Force Follow-Up

- The task force will continue in existence for at least one year to monitor progress in implementation of the Task Force recommendations.

- The Industry, Technical, and Regulatory Panels should remain impaneled for one year for the purpose of interacting with the task force.

- The task force leaders will invite the leaders of the three panels to meet in December of 1992 and June of 1993. The purpose of the meetings will be to review and evaluate progress since the issuance of this report.

- The task force leaders will send progress reports to the Chairman of FERC and the Secretary of Energy in January of 1993 and July of 1993.

Table 1. Combined Panel Recommendations on Desired Improvements

Desired Improvements	Ind.	Tech.	Reg.
1. Develop sourcebook of deliverability data -- revise annually.	●		
2. Produce glossary of deliverability terms and definitions.	●		
3. Improve timeliness of government reporting to eliminate data lags.	●	●	●
4. Periodically review reporting requirements for timeliness and accuracy.	●		
5. Develop electronic data interchange standards for industry and government.	●		
6. Obtain FCC approval of industry access to microwave and other communication bands.	●		
7. Utilize methodology from AGA, GRI and NGSA annual surveys for wellhead deliverability information.		●	
8. Conduct a one-time analysis of contractual and regulatory restraints on end-use deliverability to determine availability of gas without restraints.		●	
9. Improve communications between segments of the natural gas industry.			●
10. Encourage private sector information networking on non-price data.			●
11. Establish voluntary allocation committee(s) for regions or the nation.			●
12. Compile storage and inventory data in a central source for public access.			●
13. Improve on computer use to enhance gathering of data, timeliness of reporting, and access and exchange of data.			●
14. Develop annual statewide reporting of intrastate flows -- especially data on "basic methodology": volumes delivered during sustained period when demand substantially exceeds supply.			●
15. Develop standard state reporting regime for "back-up methodology": average daily production when demand substantially exceeds supply.			●
16. Develop statewide reporting regime for "supplemental deliverability facilities" directly to central data bank: include capacities and deliveries such as storage, LNG, etc., measured during predetermined time periods (e.g., heating seasons) on a daily, weekly and monthly basis by remote telemetering units.			●
17. Establish trunkline meter points for measurement of flow.			●
18. Develop daily/weekly pipeline reports on a small number of designated mainline segments to be transmitted via remote telemetering units to a central data collection facility or electronic bulletin board.			●
19. Report standby fuel capacity and use by electric generation facilities.			●
20. Establish a central repository for state regulators for collection and dissemination of five types of data: production, pipeline, local distribution, demand, and regulations.			●
21. Study regulatory conditions that affect deliverability, including state and federal curtailment schemes.			●
22. Continue EIA's annual report on reserves.			●
23. Provide for parallel producing state data reporting to IOGCC for comparison with EIA reports.			●

ACRONYMS AND ABBREVIATIONS

ACE	adjusted current earnings
AFUE	Average Fuel Utilization Efficiency
AGA	American Gas Association
AGCC	American Gas Cooling Center
AGS	Alberta Geological Society
AMT	Alternative Minimum Tax
ANGTS	Alaskan Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
API	American Petroleum Institute
ATEPD	Alternative Tax Energy Preference Deductions
BCF	billion cubic feet
BCF/D	billion cubic feet per day
BCM	billion cubic meters
B/D	barrels per day
BLM	Bureau of Land Management
BOE	barrels of oil equivalent
BTU	British thermal units
CAA	Clean Air Act of 1967
CAAA	Clean Air Act Amendments of 1990
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CERI	Canadian Energy Research Institute
CFC	chlorofluorocarbons
CLEV	California Low Emission Vehicle Regulations
CNG	compressed natural gas
CNR	Columbia Natural Resources
CO_2	carbon dioxide
COPAS	Council of Petroleum Accounting Societies
CWA	Clean Water Act of 1977
D&C	drilling and completion (costs)
DCF	Discounted Cash Flow
DFI	Decision Focus Inc.
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DRI	Data Resources Incorporated
DSM	Demand Side Management

E&P	exploration and production (costs)
EEA	Energy and Environmental Analysis, Incorporated
EEI	Edison Electric Institute
EIA	Energy Information Administration
EMF	Electric and Magnetic Field
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ERCB	Alberta Energy Resources Conservation Board
ERM	Enhanced Recovery Module of the Hydrocarbon Model
EUR	estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
FRB Index	Federal Reserves Boards' Index of Total Industrial Production
G&G	geological and geophysical (expenditures)
GATT	General Agreement on Tariffs and Trade
GEMS	Generalized Equilbrium Modeling System
GRI	Gas Research Institute
HDD	heating degree days
HSM	Hydrocarbon Supply Model
HVAC	Heating, Ventilating, and Air Conditioning
IDC	Intangible Drilling Costs
IEA	International Energy Agency
IGTCC	Industrial Gas Technology Commercialization Center
INGAA	Interstate Natural Gas Association of America
IOGCC	Interstate Oil and Gas Compact Commission
IPAA	Independent Petroleum Association of America
IPP	independent power producer
IRP	integrated resource planning
JAS	Joint Association Survey
KW	kilowatts
KWH	kilowatt hours
LAER	lowest achievable emission rate (controls)
LCP	least cost planning
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MAFLA	Mississippi, Alabama, Florida onshore
MCF	thousand cubic feet
MCF/D	thousand cubic feet per day
MECS	Manufacturing Energy Consumption Survey
MMBTU	million British thermal units
MMCF	million cubic feet
MMCF/D	million cubic feet per day
MMS	Minerals Management Service, Department of Interior

MOPPS (I&II)	Market Oriented Program Planning Study
MPRSA	Marine Protection, Research and Sanctuaries Act, 1972
MW	megawatts
MWH	megawatt hours
NAAQS	National Ambient Air Quality Standards
NAECA	National Appliance Energy Conservation Act
NAFTA	North American Free Trade Agreement
NARG	North American Regional Gas Model
NARUC	National Association of Regulatory Utility Commissioners
NEB	National Energy Board of Canada
NEPA	National Environmental Policy Act of 1969
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NES	National Energy Strategy
NGA	Natural Gas Act of 1938
NGL	natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGSA	Natural Gas Supply Association
NGV	Natural Gas Vehicle
NGVC	Natural Gas Vehicle Coalition
NGWDA	Natural Gas Wellhead Decontrol Act of 1989
NIMBY	Not In My Back Yard
NMS	National Marine Sanctuary Program
NORM	naturally occurring radioactive material
NOx	nitrogen oxides
NPC	National Petroleum Council
NPDES	National Pollutant Discharge Elimination System
NRRI	National Regulatory Research Institute
NUG	non-utility generator
NYGAS	New York State Gas Association
O&M	operating and maintenance (expenses)
OCS	Outer Continental Shelf
OGIFF	Oil and Gas Integrated Field File
OPA	Oil Pollution Act of 1990
OPEC	Organization of Petroleum Exporting Countries
PEMEX	Petroleos Mexicanos, national oil company of Mexico
PGC	Potential Gas Committee of the Colorado School of Mines
PIFUA	Powerplant and Industrial Fuel Use Act of 1978
PMA	Federal Power Marketing Agencies
PSC	Public Service Commission
PUC	Public Utility Commission
PUCHA	Public Utilities Holding Company Act
QBTU	quadrillion British thermal units
RACC	Refiners Acquisition Cost of Crude Oil

RCRA	Resource Conservation and Recovery Act of 1976
R&D	research and development
RD&D	research, development, and demonstration
RECS	Residential Energy Consumption Survey
ROR	rate of return
SARA	Superfund Amendments and Reauthorization Act of 1986
SCF	standard cubic feet
SDWA	Safe Drinking Water Act of 1984
SEC	Securities and Exchange Commission
SEDS	State Energy Data System
SFV	straight fixed variable
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SMP	special marketing program
SO_2	sulfur dioxide
SOx	sulfur oxides
SPP	small power producer
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TBTU	trillion British thermal units
TCF	trillion cubic feet
TRC	Texas Railroad Commission
TSCA	Toxic Substance Control Act of 1976
UDI	Utility Data Institute
UIC	Underground Injection Control program
USGS	United States Geological Survey
VOC	volatile organic compounds
WCSB	Western Canada Sedimentary Basin

GLOSSARY

ABANDONMENT

When an interstate pipeline closes facilities, stops transporting gas in interstate commerce, or stops sales of gas for resale with permission of the Federal Energy Regulatory Commission.

ALASKA NATURAL GAS Transportation (ANGTS)

A proposed pipeline to transport gas from Prudhoe Bay, Alaska, to the lower-48 states. Portions of the line were "prebuilt" prior to the flow of Alaskan gas, with the rest of the system awaiting sponsors and economically viable gas prices.

ALLOWABLE

The maximum amount of gas a specific field, lease, or well is permitted to produce.

ALTERNATIVE MINIMUM TAX (AMT)

Under the Tax Reform Act of 1986 the minimum tax was reformulated as the AMT and expanded to the point where it became the *de facto* corporate income tax for many capital-intensive firms. The AMT is imposed at 20 percent rate (24 percent non-corporate) on a broader income than that used for regular income tax, and the taxpayer pays the higher of the two taxes.

AMERICAN GAS ASSOCIATION (AGA)

The gas utility industry trade association.

ANTRIM SHALE

The Antrim shale is a formation of primarily Devonian age located in the Michigan Basin.

ASSOCIATED DISSOLVED GAS

The combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

BACK HAUL

A contractual form of natural gas transportation service, where natural gas is delivered to the shipper at a point on the pipeline system which is upstream of the point where gas is received into the system. Contractually, the natural gas is transported against the direction of natural gas flowing in the pipeline system. In most cases this type of service can be provided without the need to construct new facilities, and in operation may actually reduce the variable costs (fuel) incurred by the pipeline to provide transportation service. It also has the effect of increasing the effective capacity of the pipeline system.

BASE GAS

(*See* Cushion Gas.)

BASE LOAD GENERATING UNIT

Those generating units at electric utilities that are normally operated to meet electricity demand on a round-the-clock basis.

Base Rate

That portion of the total electric rate which covers the general costs of doing business unrelated to fuel expenses.

BCF

Billion Cubic Feet. A volumetric unit of measurement for natural gas.

Blanket Certificate (Authority)

Permission granted by the Federal Energy Regulatory Commission (FERC) for a certificate holder to engage in an activity (such as transportation service or sales) on a self-implementing or prior-notice basis, as appropriate, without case-by-case approval from the FERC.

British Thermal Unit (BTU)

A standard unit for measuring the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit at or near 39.2 degrees Fahrenheit.

Capacity Brokering

A process where an existing natural gas shipper sells or leases its contractual capacity rights to transport natural gas on a pipeline to someone else.

Certificated Capacity

The maximum volume of gas that may be stored in an underground storage facility certificated by the Federal Energy Regulatory Commission or its predecessor, the Federal Power Commission. Absent a certificate, a reservoir's present developed operating capacity is considered to be its "certified" capacity.

Certificates of Public Convenience and Necessity

Certificates required under the Natural Gas Act and issued by the Federal Power Commission/Federal Energy Regulatory Commission prior to construction or expansion of an interstate pipeline; after the pipeline showed the existence of market demand and attendant gas supply.

Christmas Tree

The valves and fittings installed at the top of a gas well to control and direct the flow of well liquids.

Citygate

A point or measuring station at which a gas distribution company receives gas from a pipeline company or transmission system.

Citygate Sales Service

Interstate pipeline natural gas sales service where the title to gas sold changes at the pipeline's interconnection with the purchasing local distribution company.

Coal Gasification

The process of placing coal steam and oxygen under pressure to produce gas.

Cofiring (reburning)

The process of burning natural gas in conjunction with another fuel to reduce air pollutants and/or take advantage of lowest available fuel prices.

Cogeneration

The sequential production of electricity and another form of useful thermal energy such as heat or steam and used for industrial, commercial heating or cooling purposes. There are basically three types; boiler steam turbine, combustion turbine with waste heat recovery steam generator, and combined cycle.

Coke Oven Gas

The gaseous portion of volatile substance driven off in the coking process after other coal chemicals are removed.

Combined Cycle

An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Commercial Consumption

Gas consumed by nonmanufacturing establishments or agencies primarily engaged in the sale of goods or services. Included are such establishments as hotels, restaurants, wholesale and retail stores, and other service enterprises; gas consumed by establishments engaged in agriculture, forestry, and fishers; and gas consumed by local, state, and federal agencies engaged in nonmanufacturing activities.

Conventional Resources

Resources included in this category are crude oil, natural gas, and natural gas liquids that exist in reservoirs in a fluid state amenable to extraction employed in traditional development practices. They occur as discrete accumulations. They do not include resources occurring within extremely viscous and intractable heavy oil deposits, tar deposits, oil shales, coalbed gas, gas in geopressured shales and brines, or gas hydrates. Gas from low-permeability "tight" sandstone and fractured shale reservoirs having in situ permeability to gas of less than 0.1 millidarcy are not included as conventional resources.

Cost-of-Service Rates

A method of rate making used by utilities under which the original cost of facilities are depreciated for an expected life, and the annual costs and the operating and maintenance costs are allocated to each service offered according to a test year and projected volumes.

Cross Subsidies

Subsidies among customers or customer classes so that one group carries a disproportionate share of the costs of providing service.

Curtailments

The rationing of natural gas supplies to an end user when gas is in short supply, or when demand for service exceeds a pipeline's capacity, usually to an industrial user and/or power generator.

Cushion Gas

The volume of gas, including native gas, that must remain in the storage field to maintain adequate reservoir pressure and deliverability rates throughout the withdrawal season.

Cycling

The process of injecting or withdrawing a percentage or all of a reservoir's working gas capacity during a particular season.

Cycling Unit (Intermediate Unit)

Units that operate with rapid load changes, frequent starts and stops, but generally at somewhat lower efficiencies and higher operating costs than base load plants. These units are generally either former base load units regulated to cycling units, or newly built units of a lower megawatt rating which require less capital investment per unit of output than required for base load units.

Decatherm

Ten therms, or 1,000,000 BTU.

Deep Gas Deposits

Deposits of gas below 15,000 feet, where the porosity and permeability are reduced by the deeply buried sediments.

Deliverability

The rate at which gas can be withdrawn from an underground reservoir. Actual rates depend on rock characteristics, reservoir pressure, and facilities such as wells, pipelines, and compressors.

Delivered

The physical transfer of natural, synthetic, and/or supplemental gas from facilities operated by the responding company to facilities operated by others or to consumers.

Demand Charge

A charge levied in a contract between a pipeline and local distribution company, electric generator, or industrial user for firm gas pipeline transportation service. The demand charge must be paid whether or not gas is used up to the volume covered by the charge.

Demand Side Management

Programs designed to encourage customers to use less natural gas or other fuels or less electricity and to use it more efficiently (i.e., conservation) or to reduce peak demand (i.e., load management).

Design Day Capacity

The volume of natural gas that a pipeline facility is designed to transport during one day, given the assumptions used in the design process, such as pressures, pipeline efficiency, and peak hourly rates.

Design Day Deliverability

The rate of delivery at which a storage facility is designed to be used when storage volumes are at their maximum levels.

Developed Operating Capacity

That portion of operating capacity which is currently available for storage use.

Devonian Shale

Any body of shale (a fine-grained, detrital, sedimentary rock with a finely laminated structure) formed from the compaction of clays and/or silts and/or middays that were deposited during the Devonian period of the Paleozoic era, from approximately 400 million to approximately 345 million years before the present.

Displacement

A method of natural gas transportation/delivery that is similar to a back haul (see above). In a displacement service, natural gas is received by a pipeline at one point and delivers equivalent volumes at another point, without necessarily transporting the natural gas in a line between the two points. Displacement service may contain elements of forward haul, back haul, and displacement to effect delivery.

Dry Natural Gas Production

Marketed production less extraction loss.

Electric Generators

Establishments that generate electricity. These include traditional electric utilities; independent power producers; and commercial and industrial establishments that generate electricity for their own use, often using cogeneration facilities, and which may sell some of the electricity to an electric utility for resale. In the NPC report, commercial and industrial generators of electricity are included in the commercial and industrial sectors and all other generators are dealt with under "electric generation."

Electric Utilities

Establishments primarily engaged in the generation, transmission, and/or distribution of electricity for sale or resale.

Electric Utility Consumption

Gas used as fuel in electric utility plants.

End-Use Sector Models

Energy and Environmental Analysis, Inc.'s process-engineering models used in the NPC Gas Study and include the Residential, Commercial, Industrial, and Electric Utility Demand Models.

End User

Anyone who purchases and consumes natural gas.

Energy Overview Model

Energy and Environmental Analysis, Inc.'s forecasting model, which simulates the natural gas supply/demand balance through the use of 3 sets of model components (End-Use Sector Models, the Pipeline Model, and the Hydrocarbon Supply Model) and used in the NPC Gas Study.

Exchange

A method of natural gas transportation/delivery among two (or more) parties. Where one party has a natural gas supply at one point, convenient to one pipeline system, and another party has gas at another point, convenient to another pipeline system, a swap is arranged. The two pipelines do not necessarily have to interconnect. Essential to the concept is that both parties receive mutual benefits. Exchange agreements usually contain some form of balancing mechanism requiring either the delivery of natural gas, in kind, or payment.

Exports

Natural gas deliveries from the continental United States and Alaska to foreign countries.

Externality

A side effect that can create benefits or costs in a transaction and which fall upon those not directly involved in, or who are external to, the transaction.

Extraction Loss

The reduction in volume of natural gas due to the removal of natural gas liquid constituents such as ethane, propane, and butane at natural gas processing plants.

Federal Power Commission (FPC)

The predecessor agency of the FERC, which was created by Congress in 1920 and was charged with regulating the interstate electric power and natural gas industries.

Federal Energy Regulatory Commission (FERC)

A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. Five members are appointed by the President of the United States and, upon confirmation by the Senate, serve fixed terms. This independent agency is administered by the Chairman of the five-person commission. No more than three of the five members may belong to the President's political party.

FERC Order 436

An order issued October 9, 1985, by the FERC, which created a voluntary blanket certificate transportation program. Under this program, participating pipelines were authorized to provide firm and interruptible transportation to any willing shipper without prior case-specific FERC approval. Pipelines providing this service are required to serve on a non-discriminatory basis any shipper willing to meet the terms and conditions of the pipeline's tariff. Participating pipelines were also subject to a requirement that they allow existing firm sales customers to convert their sales service to firm transportation service.

FERC Order 451

Order 451 was issued in 1986 and eliminated old gas "vintaging" pricing, which was based on the date of first production of the gas reserves. The Order established a new ceiling price for all vintages of old gas, which a pipeline purchaser could purchase or release under a procedure called "good faith negotiations."

FERC Order 500

In Associated Gas Distributors vs. FERC, Order 436 was remanded back to FERC. In response, FERC issued Order 500 in August 1987, which restated Order 436 with two major changes: elimination of the customer contract demand reduction option, and creation of a take-or-pay crediting mechanism. This mechanism was designed to affect take-or-pay obligations of interstate pipelines caused by Order 436 transportation.

FERC Order 490

Order 490 was issued in 1988 and established an expedited abandonment procedure for gas under expired or terminated contracts.

FERC Order 636 (*See also* Unbundling)

An order issued April 8, 1992, by the FERC, requiring open-access interstate pipeline companies to unbundle their transportation delivery services from their natural gas sales services. Order 636 also required other changes designed to enhance the access to gas supplies, no matter who owned or sold them, on an equal basis.

Field

A single pool or multiple pools of hydrocarbons grouped on, or related to, a single structural or stratigraphic feature.

Finding Rate

Some measure of "added proved reserves" divided by some measure of either time or the physical or investment effort expended to generate them. There are many different specific formulations in use.

Firm Gas

Gas sold on a continuous and generally long-term contract.

Firm Service

Service offered to customers (regardless of class of service) under schedules or contracts that anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses that permit unexpected interruption in case the supply to residential customers is threatened during an emergency.

Flared

Natural gas burned in flares at the base site or a gas-processing plants.

Fracturing

Improvement of the flow continuity between gas-bearing reservoir rock and the wellbore by erecting fractures which extend the distances into the reservoir.

Fuel Cells

A fuel cell, configured like a battery, combines natural gas and oxygen in an electrochemical reaction that produces electricity, heat, and water (often in the form of steam).

Gas Bubble

Surplus gas deliverability at the wellhead.

Gas Condensate Well

A gas well producing from a gas reservoir containing considerable quantities of liquid hydrocarbons in the pentane and heavier range, generally described as "condensate."

Gas Well

A gas well completed for the production of natural gas from one or more gas zones or reservoirs.

Gathering System

Facilities constructed and operated to receive natural gas from the wellhead and transport, process, compress, and deliver that gas to a pipeline, LDC, or end user. The construction and operation of gathering systems is not a federally regulated business, and in some states is not regulated by the state.

Generating Unit

Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (Electricity)

The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (WH).

Generator

A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity

The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Greenfield

A "new" site for the construction of an electric generation plant; in other words, a location that did not previously have a generation unit.

Greenhouse Effect

The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid-Type System

This term describes a natural gas pipeline company that operates facilities which physically interconnect at numerous points within its service area. Typically such a system receives gas from a variety of sources from both ends of its system and is characterized by gas flows which are difficult to trace in a linear fashion.

Gross Withdrawals

Full well-stream volume, including all natural gas plant liquids and all nonhydrocarbons gases, but excluding lease condensate.

Heating Value

The average number of British thermal units per cubic foot of natural gas as determined from tests of fuel samples.

Hub

A hub is a location where gas sellers and gas purchasers can arrange transactions. The location of the hub can be anywhere multiple supplies, pipelines, or purchasers interconnect. "Market centers" are hubs located near central market areas. "Pooling points" are hubs located near center supply production areas. Physical hubs are found at processing plants, offshore platforms, pipeline interconnects, and storage fields. "Paper" hubs may be located anywhere parties arrange title transfers (changes in ownership) of natural gas.

Hydrates

Gas hydrates are physical combinations of gas and water in which the gas molecules fit into a crystalline structure similar to that of ice. Gas hydrates are considered a speculative source of gas.

Hydrocarbon Supply Model

Energy and Environmental Analysis, Inc.'s model of the U.S. and Canada's potential recoverable resource base. This model seeks to show the impact of technological advancements and exploratory and development drilling activity and was used in the NPC Gas Study.

Imports

Gas receipts into the United States from a foreign country.

In-Place Gas Resource

The total in-place gas is the summation of gas already produced, the technically recoverable resource, and the remaining in-place resource.

Incentive Regulation

An alternative to, or modification of, cost of service regulation, which is used in markets that lack sufficient competition (examples include price caps, zone of reasonableness, bounded rates, sharing of efficiency gains, and incentive rates of return).

Independent Power Producers (IPPs)

Wholesale electricity producers that are unaffiliated with franchised utilities in their area. IPPs do not possess transmission facilities and do not sell power in any retail service territory.

Industrial Consumption

Natural gas consumed by manufacturing and mining establishments for heat, power, and chemical feedstock.

Industrial Consumers

Establishments engaged in a process that creates or changes raw or unfinished materials into another form or product. Generation of electricity, other than by electric utilities is included.

Integrated Resource Plan (IRP)

A plan or process used by utilities to evaluate both supply-side and demand-side measures when seeking to prepare for meeting future energy needs and to do so at lowest total costs. ("Least cost" or "best cost" planning is sometimes used synonymously with integrated resource planning.)

Intermediate Load (Electric System)

The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peak load, or the load over a specified time period.

Interruptible Gas

Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company or pipeline under certain circumstances, as specified in the service contract.

Interruptible Service

A sales volume or pipeline capacity made available to a customer without a guarantee for delivery. "Service on an interruptible basis" means that the capacity used to provide the service is subject to a prior claim by another customer or another class of service (18 CFR 284.9(a)(3)). Gas utilities may curtail service to their customers who have interruptible service contracts to adjust to seasonal shortfalls in supply or transmission plant capacity without incurring a liability.

Interstate Pipeline Company

A company subject to regulation by the Federal Energy Regulatory Commission pursuant to the Natural Gas Act of 1938 because of its construction and/or operation of natural gas pipeline facilities in interstate commerce.

Interstate Natural Gas Association of America (INGAA)

Trade group that represents interstate pipeline companies.

Intrastate Pipeline Company

A company that operates natural gas pipeline facilities which do no cross a state border.

Kilowatt

One thousand watts. (*See* Watt.)

Large Diameter Pipe

High pressure natural gas pipeline is constructed, typically, of steel, in different sizes from one inch, outside diameter (O.D.) to 42 inches. Typically "large diameter pipe" is larger than 20 inches, O.D.

Lease and Plant Fuel

Natural gas used in well, field, and lease operations, (such as gas used in drilling operations, heaters, dehydrators, and field compressors), and as fuel in natural gas processing plants.

Light-Handed Regulation

Regulation characterized by reliance on market forces where they are available to help ensure fair access and stable prices. Generally, under such a scheme, companies are given significant discretion to enter and leave a particular service, and over what rate it charges. While such activities are not "deregulated" in the normal sense of the phrase, regulatory scrutiny is usually generic and compliance oriented, rather than intrusive.

Line Pack

The volume of natural gas contained, in a point of time, within the pipeline. Also, a technique to fill a pipeline to its maximum capacity in anticipation of high demands, or hourly fluctuations in demand.

Liquefied Natural Gas (LNG)

Natural gas that has been reduced to a liquid stage by cooling to -260 degrees Fahrenheit and thus sustains a volume reduction of approximately 600 to 1.

Load (Electric)

The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Local Distribution Company (LDC)

A company that distributes natural gas at retail to individual residential, commercial, and industrial consumers. LDCs are typically granted an exclusive franchise to serve a geographic area by state or local governments, subject to some requirement to provide universal service. Rates and terms and conditions of service are typically (but not always) subject to regulation.

Looping

A method of expanding the capacity of an existing pipeline system by laying new pipeline adjacent to an existing pipeline and connected to the existing system at both ends.

Low Permeability

Gas that occurs in formations with a permeability of less than 0.1 millidarcy.

Manufactured Gas

A gas obtained by destructive distillation of coal, or by the thermal decomposition of oil, or by the reaction of steam passing through a bed of heated coal or coke. Examples are coal gases, coke oven gases, producer gas, blast furnace gas, blue (water) gas, carbureted water gas. BTU content varies widely.

Market Center

A place, located near natural gas market areas, where many gas sellers and gas buyers may arrange to buy/sell natural gas. See "Hub."

Marketed Production

Gross withdrawals less gas consumed for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations.

MCF/D

"Thousand cubic feet of natural gas per day." A volume unit of measurement for natural gas.

Megawatt

One million watts of electric capacity. (*See* Watt.)

Minimum Bill

A distributor's obligation to take or pay for the gas volumes specified in its firm service agreements with the pipeline.

MMBTU

"Million British Thermal Units." A unit of measurement of the heating content, as measured in BTU, of natural gas.

MMCF/D

"Million cubic feet of natural gas per day." A volume unit of measurement for natural gas.

National Energy Board

The agency of the Canadian federal government which regulates international and inter-provincial and natural gas trade with(in) Canada. The "NEB" is the Canadian counterpart to the FERC, and like FERC also regulates electricity.

Native Gas

The gas remaining in a reservoir at the end of a reservoir's producing life. After a reservoir is converted to storage, remaining gas becomes part of the cushion gas volume.

Natural Gas

A gaseous hydrocarbon fuel. Primarily made up of the chemical compound methane, or CH_4. Natural gas is found in underground reservoirs, often in combination with oil, and other hydrocarbon compounds.

Natural Gas, Wet After Lease Separation

The volume of natural gas remaining after removal of lease condensate in lease and/or field separation facilities, if any, and after exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Natural gas liquids may be recovered from volume of natural gas, wet after lease separation, at natural gas processing plants.

Natural Gas Act of 1938

Act passed by Congress which regulates the transportation and sale of natural gas in interstate commerce. This statute is administered by the FERC.

Natural Gas Council

Formed in 1992 through the four major U.S. gas industry trade groups to promote awareness of the potential of natural gas and to develop a unified gas industry.

Natural Gas Policy Act of 1978

An act of Congress which effected the phased decontrol of certain categories of natural gas wellhead prices.

Natural Gas Supply Association

Trade group that represents natural gas producers, whether integrated or small.

Natural Gas Wellhead Decontrol Act of 1989

This Act fully decontrols natural gas wellhead prices effective January 1, 1993.

Netback Price

The price for natural gas the producer receives "at the wellhead" as determined by subtracting the cost of all delivery services from the price received "at the burnertip" for natural gas. In a competitive end-use market, it is presumed that a producer would receive no more than the netback price for its gas.

New Fields

A category of the resource base which represents gas that is yet to be discovered. This category is quantified based on risked assessments attributing geologic similarities from known areas, defined as those resources estimated to exist outside of known fields on the basis of broad geologic knowledge and theory.

No-Notice Transportation Service

A term used in FERC Order 636 to describe firm transportation service equivalent in quality to the delivery service provided as an integral part of traditional firm pipeline natural gas sales services.

Nonconventional Gas

Resource that includes shale gas, coalbed methane, and tight gas as these are in a relatively early stage of technical development.

Nonhydrocarbon Gases

Typical nonhydrocarbon gases that may be present in reservoir natural gas, such as carbon dioxide, helium, hydrogen sulfide, and nitrogen.

NORM

"Naturally Occurring Radioactive Material" in exploration and production operations originates in subsurface oil and gas formations and is typically transported to the surface in produced water, both onshore and offshore.

Off-Peak

Periods of time when natural gas pipeline facilities are typically not flowing natural gas at design capacity.

Offshore Reserves and Production

Unless otherwise indicated, reserves and production that are in either state or federal domains, located seaward of the coastline.

Oil-Equivalent Gas

Gas volume that is expressed in terms of its energy equivalent in barrels of oil (BOE). One BOE equals 5,650 cubic feet of gas.

Open-Access Transportation

Interstate natural gas transportation service, available to any willing, credit-worthy shipper, subject to the availability of capacity, on a non-discriminatory basis. (*See* FERC Order 436).

Operating Capacity

The maximum volume of gas an underground storage field can store. This quantity is limited by such factors as facilities, operational procedure, confinement, and geological and engineering properties.

Outer Continental Shelf (OCS)

The undersea area offshore from the coastline of a continent. This area may stretch for many miles from the coastline and be covered by shallow ocean. The Gulf Coast adjacent to Texas, Louisiana, Mississippi, and Alabama is an OCS area with substantial natural gas fields currently providing a significant source of natural gas supplies for the United States. The federal offshore usually starts 3 miles offshore (e.g., Louisiana), but starts 10 miles offshore of Texas.

Peak Day

The day of maximum demand for natural gas service. In any given area, the "peak day" usually occurs on the coldest day of the year, when demand for natural gas for heating is at its highest. Because each part of the country experiences different weather conditions, the peak day for each region or area is usually different. In some parts of the country, such as the Southeast and the Southwest Central regions, the peak day may occur on the hottest day of the year, when demand for space cooling drives electric generation demand to its highest levels.

Peak-Day Deliverability

The rate of delivery at which a storage facility is designed to be used for peak days.

Peaking Unit

An electric generation unit that is only run to serve "peak" demand. An electric generation unit is normally operated during the hours of highest daily, weekly, or seasonal load. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on a "round-the-clock" basis.

***Phillips* Decision**

In 1954, the U.S. Supreme Court in *Phillips Petroleum Company v. Wisconsin* interpreted the Natural Gas Act as requiring wellhead price of interstate gas to be regulated by the Federal Power Commission.

Pipeline Fuel

Gas consumed in the operation of pipelines, primarily in compressors.

Pipeline

A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural and/or supplemental gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use. Also refers to a company operating such facilities.

Pipeline Model

The EEA (Energy and Environmental Analysis, Inc.) model used in the NPC Gas Study, which simulates gas flow from U.S. and Canadian producing regions to consuming regions.

Play

A group of geologically related known accumulations and/or undiscovered accumulations or prospects generally having similar hydrocarbon sources, reservoirs, traps, and geological histories.

Pooling Point

Production area pooling points are areas where gas merchants aggregate supplies from various sources, and where title passes from gas merchant to pipeline shipper. "Paper" pooling areas are places where aggregation of supplies occurs and where pipeline balancing and penalties are determined. (*See* FERC Order 636; Hub.)

Power Pool

An arrangement used in many regions whereby all dispatchable electric generation is under the operational control of a dispatching center controlled by the power pool, not the individual company that owns the generating equipment.

Powerplant and Industrial Fuel Use Act of 1978

This Act was enacted as part of the National Energy Plan and prohibited the use of oil and gas as primary fuel in newly built power generation plants or in new industrial borders larger than 100 million BTU per hour of heat input. PIFUA also limited the use of natural gas in existing power plants based on fuel used during 1974-76, and prohibited switching from oil to gas.

Prebuild

The "Prebuild" System was authorized in 1977 and provides natural gas from Alberta, Canada, to markets in California and the Midwest. The "prebuild" system is Phase I of the Alaska Natural Gas Transportation System.

Production, Wet After Lease Separation

Gross withdrawals less gas used for repressuring and nonhydrocarbon gases removed in treating or processing operations.

Proration Policy

Policies within some gas-producing states that set production limits in order to protect the correlative mineral rights of producers and royalty owners and to prevent physical waste.

Prospect

A geological feature having the potential for trapping and accumulating hydrocarbons.

Proved Reserves

The most certain of the resource base categories as they represent estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Rate Base

The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return.

Refinery Gas

Noncondensate gas collected in petroleum refineries.

Regulatory Lag

Length of time between occurrence of a cost by a regulated entity and the reflection of that cost in the actual rates.

Renewable Energy Sources

Sources of energy, usually for electric generation, that include hydropower, geothermal, solar, wind, and biomass.

Repressuring

The injection of gas into oil or gas reservoir formations to effect greater ultimate recovery.

Reserve Appreciation

The portion of the conventional resource base that results from the recognition that currently booked proved reserves are conservative by definition and will continue to grow over time. This component represents the growth of ultimate recovery (cumulative production plus proved reserves) from known fields that occurs over time.

Reserve Growth

Composed of new reservoirs, extensions, and net positive revisions.

Reserve-to-Production Ratio

Used as an indicator that measures the relative size of ready inventory of gas supply to the current production rate.

Reservoir Pressure

The force within a reservoir that causes the gas and/or oil to flow through the geologic formation to the wells.

Residential Consumption

Gas consumed in private dwellings, including apartments, for heating, air conditioning, cooking, water heating, and other household uses.

Resource Base

Composed of proved reserves, conventional resources (reserve appreciation and new fields), and nonconventional resources (coalbed methane, shales, tight gas).

Resource Cost Curve

A curve that portrays estimates of the wellhead gas price required to develop a certain volume of the resource base and yield a minimum rate of return to the investor.

Resources

Known or postulated concentrations of naturally occurring liquid or gaseous hydrocarbons in the earth's crust which are now or which at some future time may be developed as sources of energy.

Right-of-way

Either a permanent or temporary (during construction) right of access to privately held land for the purpose of constructing and locating pipeline or related facilities. Although ownership remains, in many cases, with the original landowner, the pipeline purchases the right to locate a pipeline under a specific piece of property and the right of access to that land for inspection and maintenance activities. Pipeline right-of-way may be anywhere from 25 feet to 100 feet wide. Typically, at least 75 feet is desired for construction activities, while only 25 feet to 50 feet are maintained as permanent right-of-way.

Risked (Unconditional) Estimates

Estimated quantities of the volumes of oil or natural gas that may exist in an area, including the possibility that the area is devoid of oil or natural gas are risked (unconditional) estimates. Estimates presented in this report are of this nature. For this study, the estimated conventional resource values were used in the model as certain quantities (occurrence probability of 1.0), and the sensitivity of the model results to higher and lower resource estimates was evaluated without quantifying the occurrence probabilities.

Royalty

The gas producer gives the mineral owner a royalty in the form of a share of the gross production of gas from the property free and clear of any production costs or sells the royalty share of gas and gives the owner the gross proceeds in cash.

Section 29 of the Internal Revenue Code

Under this section, income tax credits are available to producers of "nonconventional" fuels, such as gas produced from geopressured brine, Devonian shale, coal seams, tight gas. To be eligible for the credit, gas from nonconventional sources must come from wells drilled before January 1, 1993, and must be produced before January 1, 2003.

Sour Gas

Natural gas with a high content of sulfur and this requires purification before use.

Special Marketing Programs

The FERC permitted pipelines to implement programs that allowed large industrial consumers to arrange purchases of cheaper spot market gas from producers, marketers, and pipelines, with the pipelines serving as only the transporter. These programs were ruled discriminatory by the court and ceased in 1985.

Spot Purchases

A single shipment of gas fuel or volumes of gas, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of gas requirements, to meet unanticipated needs, or to take advantage of low prices.

Steady State Flow

A method of designing natural gas pipeline facilities to meet daily volumetric requirements. Under this method, it is assumed that the same quantity of natural gas flows during each of the 24 hours during a day.

Storage Additions

Volumes of gas injected or otherwise added to underground natural gas reservoirs or liquefied natural gas storage.

Storage Field

A facility where natural gas is stored for later use. A natural gas storage field is usually a depleted oil- or gas-producing field (but can also be an underground aquifer, or salt cavern). The wells on these depleted fields are used to either inject or withdraw gas from the reservoir as circumstances require.

Storage Volume

The total volume of gas in a reservoir. It is comprised of the cushion and working gas volumes.

Storage Withdrawals

Volumes of gas withdrawn from underground storage or liquefied natural gas storage.

Straight Fixed Variable (SFV)

An interstate pipeline transportation rate design that includes all of the fixed costs as part of the reservation change. Under the Modified Fixed Variable (MFV) rate design, costs are divided and some of the fixed costs are allocated back to the demand change.

Sunshine Act

Act passed by Congress with the intent to prevent decisions from being made outside the protection afforded by exposure to public scrutiny.

Synthetic Natural Gas

A manufactured product chemically similar in most respects to natural gas, resulting from the conversion or reforming of petroleum hydrocarbons or from coal gasification. It may easily be substituted for or interchanged with pipeline quality natural gas.

System Supply

Gas supplies purchased, owned, and sold by the supplier or local distribution company to the ultimate end user. System gas is subject to FERC or state tariff and is generally sold under long-term (contract) conditions.

Take-or-Pay

A clause in a natural gas contract that requires that a specific minimum quantity of gas must be paid for, whether or not delivery is actually taken by the purchaser. Contracts entered into currently do not generally include a take-or-pay clause.

Technically Recoverable Resource

Is composed of proved reserves and assessed resources. Assessed resources are that portion of the in-place resource which is estimated to be recoverable in the future at various assumed technology and price levels.

Therm

One hundred thousand British thermal units.

Tight Gas

A component of nonconventional resources which is gas found in low permeability formations (0.1 millidarcy or less).

Top Gas

(*See* Working Gas.)

Transient Flow

A method of designing natural gas pipeline facilities to meet the hourly fluctuations in demand.

Unbundling

On April 8, 1992, the FERC issued Order 636, requiring interstate natural gas pipelines, operating under the FERC's open-access transportation program, to unbundle natural gas sales services from the transportation/delivery service. In practice, this requires affected pipelines to sell natural gas at the pipeline's physical receipt points where natural gas enters the pipeline's facilities, or at designated pooling points. The transportation service necessary to affect delivery of this gas to the customer would be provided under a separate contract. Pipelines would also be required to provide unbundled, separate, storage services. In theory, this will allow all firm customers of the pipelines to purchase natural gas from anyone, with assurance that the delivery service provided by the pipeline will be the same.

Underground Storage

The storage of natural gas in underground reservoirs at a different location from which it was produced.

Underground Storage Injections

Gas from extraneous sources put into underground storage reservoirs.

Underground Storage Withdrawals

Gas removed from underground storage reservoirs.

Undiscovered Conventional Resources

Conventional resources estimated to exist, on the basis of broad geologic knowledge and theory, outside of known fields. Also included are resources from undiscovered pools within the areal confines of known fields to the extent that they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions. For the purposes of this study, undiscovered conventional resources are a portion of the total resource base. Conventional resources are those recoverable using current recovery technology and efficiency but without reference to economic viability. These accumulations are considered to be of sufficient size and quality to be amenable to conventional recovery technology.

Uniform Code

The establishment of a consistent code of regulations that is available to all jurisdictions.

Uniform System of Accounts

Prescribed financial and accounting rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

Vented

Gas released into the air on the base site or at processing plants.

Vintaging

A method for pricing gas at the wellhead that was committed to interstate commerce prior to the passage of the Natural Gas Policy Act of 1978. Price was determined in part by the year in which the gas was dedicated to interstate commerce or the year in which drilling of the well actually commenced. Vintaging was eliminated by FERC Order 451 in November 1986.

Watt

The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthours

The electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electrical circuit steadily for 1 hour.

Well Workover

Work done on a well that improves the mechanical condition of the well or work that treats the reservoir in order to improve gas flow.

Working Gas

The volume of gas in reservoir above the designed level of the cushion gas.

INDEX

G

I

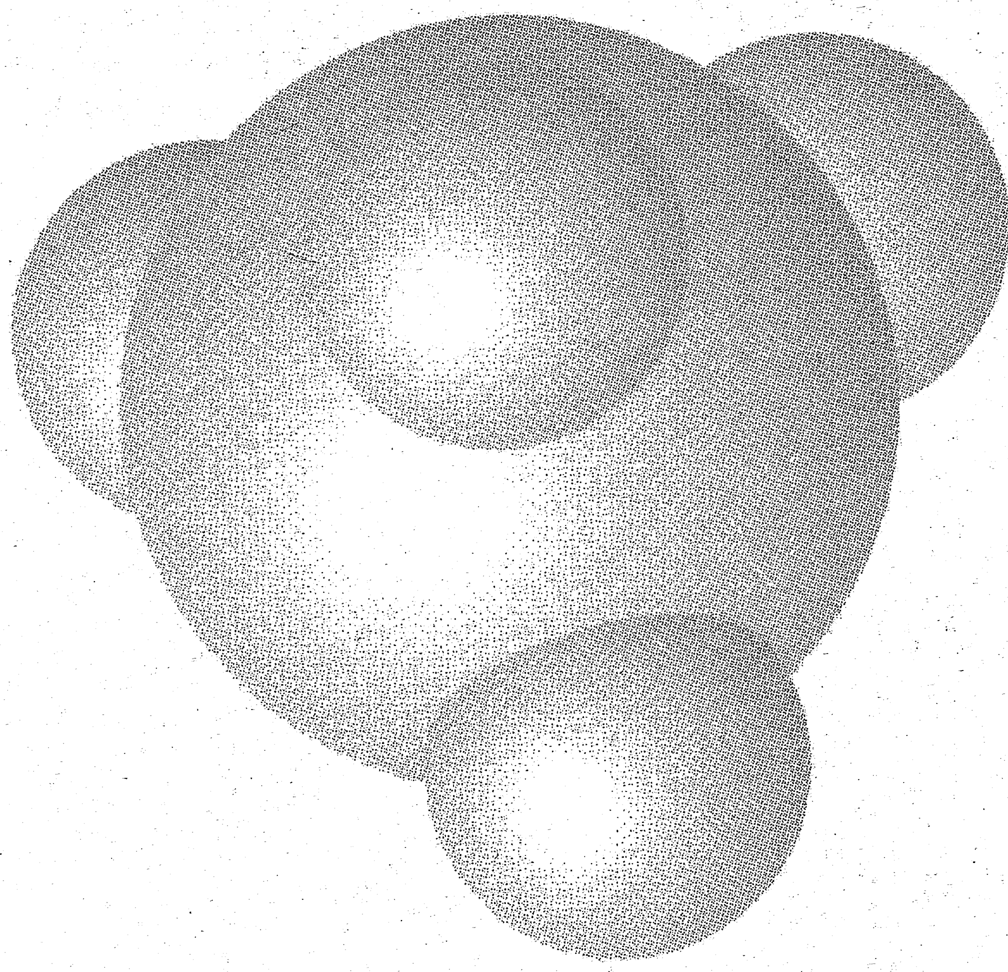
L

M

N

O

NOTES



recycled paper