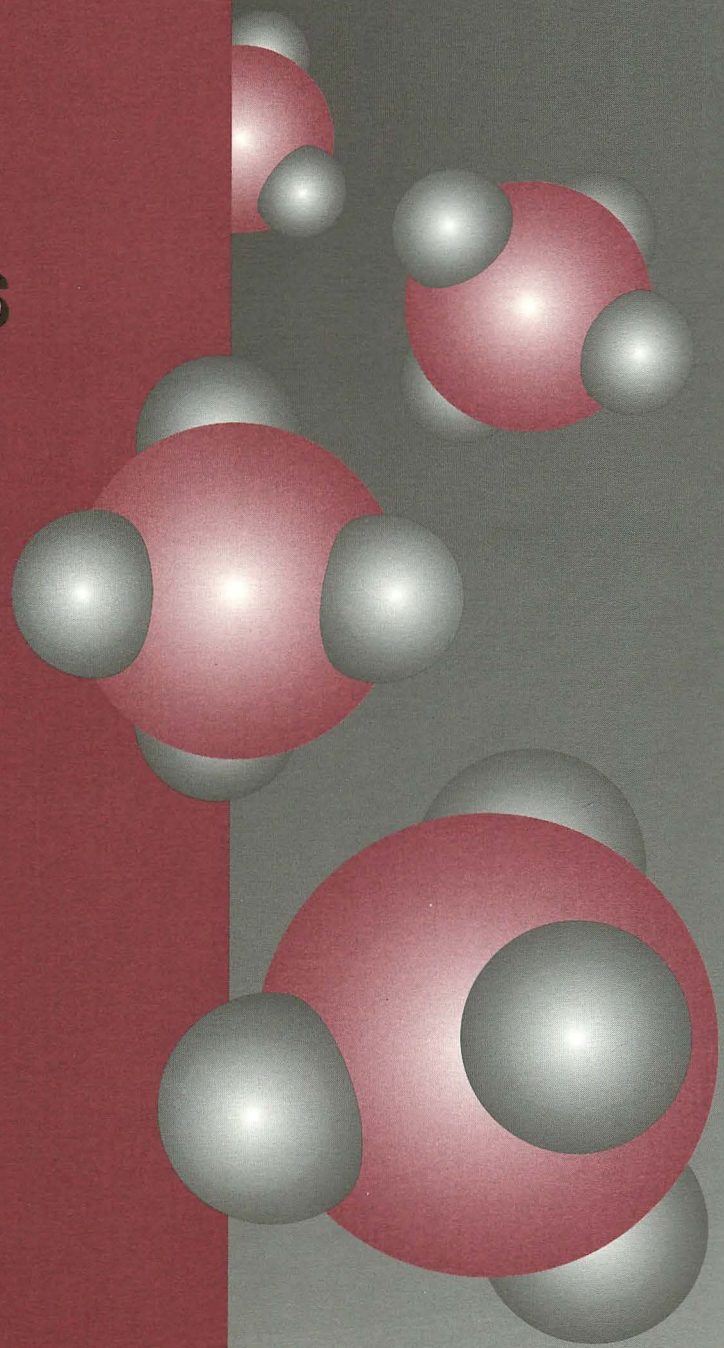
The Potential for Natural Gas in the United States



Summary

December 1992
National Petroleum Council

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

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:

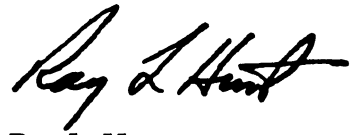
1. Natural gas can be produced and delivered in volumes sufficient to meet expanding market needs at competitive prices.
2. Natural gas is a clean-burning fuel, and can be used in a variety of applications to satisfy environmental requirements.
3. Natural gas is a secure, primarily domestic source of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

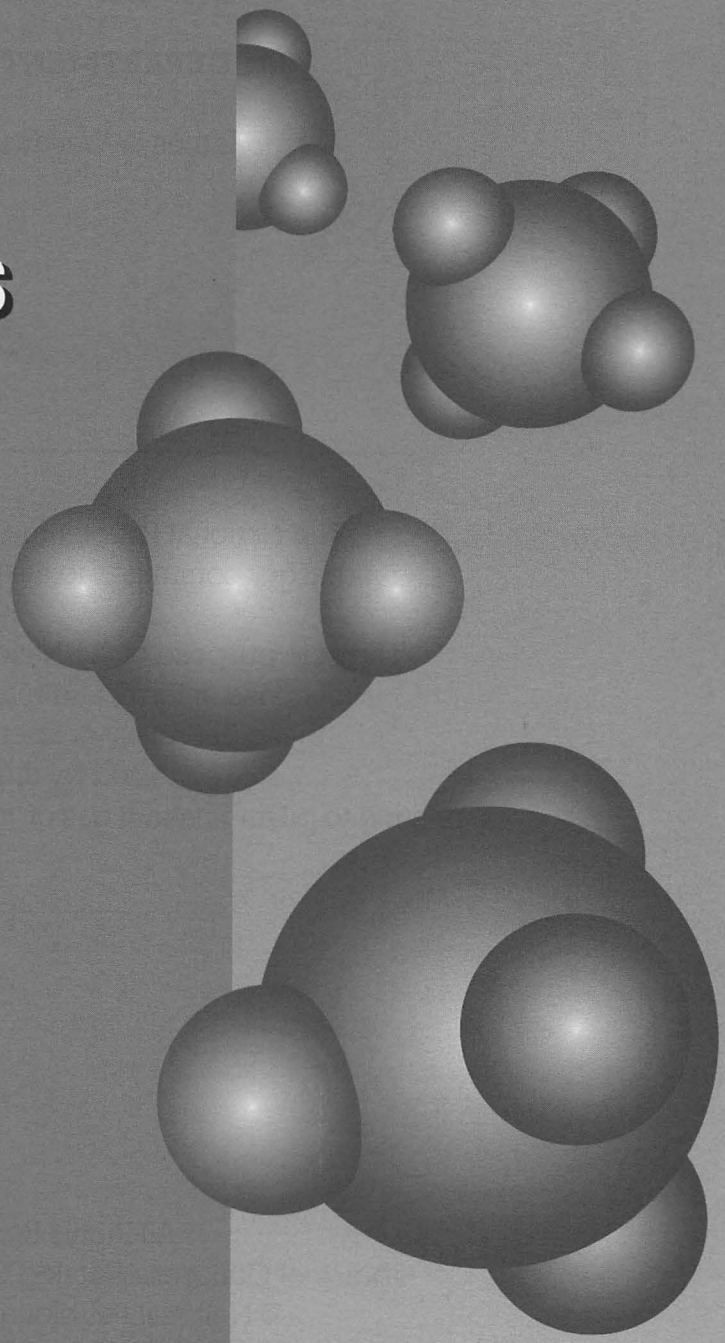
Respectfully submitted,



Ray L. Hunt
Chairman

Enclosure

The Potential for Natural Gas in the United States



Summary

December 1992
National Petroleum Council

Committee on Natural Gas
Frank H. Richardson, Chairman

NATIONAL PETROLEUM COUNCIL

Ray L. Hunt, *Chairman*
Kenneth T. Derr, *Vice Chairman*
Marshall W. Nichols, *Executive Director*

U.S. DEPARTMENT OF ENERGY

James D. Watkins, *Secretary*

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.

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PREFACE

The National Petroleum Council (NPC), an advisory body to the Secretary of Energy, has completed a study on natural gas, spanning issues from production through consumption. The Secretary, in his letter to the NPC requesting this study, specifically asked for:

> **a comprehensive analysis of the potential for natural gas to make a larger contribution . . . to our Nation's energy supply . . . [and] . . . to consider carefully the . . . potential barriers that could impede the deliverability of gas to the most economic, efficient and environmentally sound end-users.**

(See Appendix A for the complete text of the Secretary's letter.)

The NPC established a Committee on Natural Gas to develop a response to the Secretary's request. The Committee was chaired by Frank H. Richardson, President and Chief Executive Officer, Shell Oil Company, Houston, Texas. Mr. Richardson was assisted by Kenneth L. Lay, Chairman and Chief Executive Officer, Enron Corp., who served as Vice Chairman, Transmission, and Eugene A. Tracy, Immediate Past Chairman of the Executive Committee, Peoples Energy Corporation, who served as Vice Chairman, Distribution. The Government Cochairman for the study was James G. Randolph, Assistant Secretary for Fossil Energy, U.S. Department of Energy. The Committee was assisted by a Coordinating Subcommittee and four task groups. (See Appendix B for study group rosters.)

The response to the Secretary's request has taken nearly two years of study and analysis and has involved contributions from some 200 individuals in industry, government, trade associations, academia, and private enterprise. This study has brought together representatives from all segments of the natural gas industry (major and independent producers, transmission companies, local distribution companies, and marketers) as well as end users and federal and state regulators.

Additionally, the study utilized focus group interviews with participants representing consumer advocates, regulators, various customer classes, and the different industry segments. The focus group participants were encouraged to provide input on where the natural gas industry was not meeting their specific requirements, what concerns they had about the industry, and suggestions on how the industry could improve. These results were considered by the NPC study members in analyzing the potential barriers to increased use of natural gas and developing recommendations for moving the industry toward its goals.

Results from the study have been assembled into six volumes, the first of which is this summary of the overall findings and recommendations along with the methodology used in conducting the study. This Summary volume is supported by reports of each of the four task groups created by the Natural Gas Committee. Volumes II through V cover Source and Supply, Demand and Distribution, Transmission and Storage, and Regulatory and Policy Issues, respectively. The final volume contains descriptions of the computer models used in the study and selected output from the analyses. The Executive Summary section of this volume is reprinted as a separate volume. Copies of these volumes may be obtained from the NPC by using the order form in the back of this Summary volume.



OVERVIEW

Over the course of the study, the NPC assessed (1) the growth opportunities for natural gas under two different scenarios, (2) the economic potential for satisfying growing demand with the domestic gas resource base and available imports, (3) the ability of the transportation and storage system to meet the increased demand, and (4) how the regulatory environment affects the operations of the industry. The NPC further identified actions by government and industry that are necessary for natural gas to compete effectively for a larger fraction of the nation's energy requirements.

Results from the study have been consolidated into four key findings and two categories of recommendations. The four key findings are:

- **The natural gas resource base is abundant and can be produced and delivered at prices that allow both expansion of the market and continued development of the resource.** The study results indicate that sufficient new natural gas supplies can be delivered at competitive prices, even though a substantial portion of this gas is in reservoirs that are more expensive to develop and require sustained real growth in wellhead gas prices and time to bring on the new production. The continued evolution of technology and efficiency improvements combine to reduce delivered prices below what they would have been without these advances, and tend to mitigate the increasing cost of developing the more expensive supplies. The study participants believe that, with the proper emphasis on research and development, technology impacts in the future will be even greater than evidenced in the past.
- **The natural gas market is increasingly diverse, with new challenges and opportunities.** Natural gas has potential growth opportunities in all existing market segments and several new technologies, but will face substantial challenges from the other traditional fuel sources as well as improved energy efficiencies and conservation. Regional and site-specific factors will be important in determining the growth potential for natural gas.
- **Increased reliance on competitive market forces has improved the gas industry's ability to serve customer needs in a diverse and expanding marketplace.** New regulatory policies are encouraging competition and the natural gas industry is responding by providing additional value-added services, flexible contracting options, and increased attention to customer needs. Sound management, operational mechanisms, contract diversity, and active use of financial markets can work together to manage risk and reduce the short-term volatility that is likely to occur as the industry moves through various transitional phases.
- **The gas industry faces significant challenges requiring proactive steps by industry and government,** as evidenced from the responses of both the study participants and the focus groups. Potential customers are concerned about the ability of the industry to deliver gas when and where it is needed, particularly during

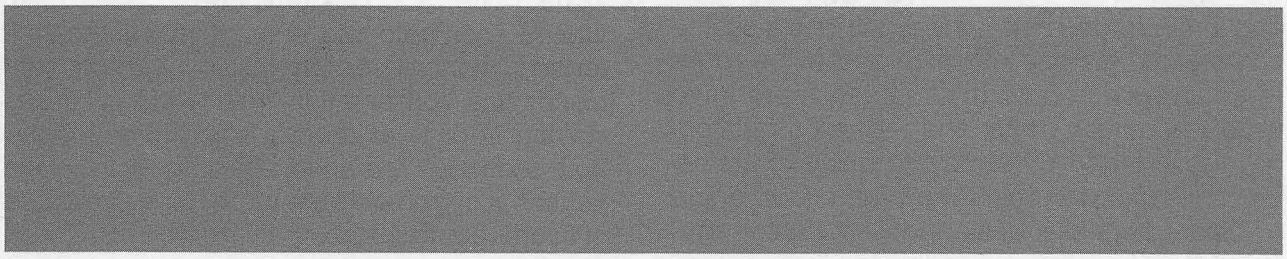
times of peak demand. Additionally, the industry does not have a good public image and has not been sufficiently effective in the past at marketing natural gas, in spite of its inherent beneficial qualities, and has been overdependent on regulation for setting direction and resolving conflicts.

The two general categories of recommendations that have emerged from the study are directed toward government officials and industry, respectively:

- **Federal, state, and local officials need to allow competitive market forces to continue to develop and work.** They need to promote and support policies and regulations that foster customer choice and reduce regulatory uncertainty, and eliminate programs, policies, and procedures, both regulatory and environmental, that unduly increase the delivered cost of natural gas. In addition, regulators and legislators will need to exercise restraint during periods of price and supply volatility as the industry adjusts to the changing marketplace.

- **Industry needs to make the market work.** These recommendations involve: continued and accelerated development of technology and procedures to reduce the delivered cost of natural gas; promotion and commercialization of new end-use technologies; development of new and innovative strategies for dealing with environmental issues; concentration of efforts to improve the reliability of supply and delivery systems; increased customer focus in marketing; and increased leadership efforts.

The adoption of the principles embodied by these recommendations is a necessary prerequisite to achieving the expectation set out in the request from the Secretary, **"that natural gas can make a greater contribution to the energy security and environmental enhancement of our Nation."**





FINDINGS AND RECOMMENDATIONS

The domestic natural gas industry of the 1990s finds itself in transition. The industry has changed dramatically since the middle part of this century when gas was considered a by-product of oil production and a surplus of gas stimulated large expansions in transmission and distribution systems. These systems were historically considered natural monopolies and regulated by different entities with little attention to a coordinated, forward-looking energy policy. The consumption of gas in the United States grew rapidly until the early 1970s and then declined due to regulated gas prices and the resultant curtailments. The incorrect perception emerged that natural gas was a scarce commodity, the use of which had to be regulated even more tightly. Those fears have eased in recent years, and federal regulators have responded by removing many of the restrictions that were hindering the effective and efficient operations of the industry. State regulators have begun to follow that lead.

At the same time, there have been emerging concerns about the overall growth of energy consumption in the nation and the world, and about the potential environmental impacts associated with that growth. Also, the use of short-term, least-cost purchase strategies has created uncertainties on both the supply and demand sides of the energy equation. Regulatory agencies have begun seeking ways to balance energy supply and demand through Integrated Resource Planning, which includes economic optimization of supply-side and demand-side measures.

These concerns and uncertainties add to the complexity of responding to the Secretary's request to study the potential for expanding the production, distribution, and use of natural gas. What will be the overall energy demand levels in the United States and the regulatory and economic framework within which natural gas will compete with other energy sources? The NPC concluded that it could not answer these questions with sufficient certainty and elected to specify two different scenarios for conducting a quantitative evaluation of natural gas growth opportunities over the long term.

The two scenarios are sufficiently different to provide independent alternative views of future energy requirements. The first scenario anticipates an environment characterized by moderate economic and energy growth, with world oil prices increasing gradually in real terms. The second scenario anticipates more limited economic and energy growth, characterized by increased emphasis on energy efficiency and conservation, with world oil prices staying at or near today's level in real terms. Both scenarios are believed to be realistic and neither is considered the more likely projection of future requirements.

The principal time frame covered by the study extends to the year 2010. This time horizon was considered the minimum needed for investment decisions, which span 10 to 20 years and depend on projections of long-term supply. In addition, the supply of natural gas was examined for its ability to satisfy potential domestic gas demands to the year 2030 at various assumed price levels.

The NPC used a set of supply, transportation, and demand models to estimate the future natural gas supply/demand balance and resultant equilibrium gas prices under each scenario. These results should not be interpreted as forecasts of prices or volumes, but rather as reasonable projections of what could occur under the assumed scenarios. Under the scenario with moderate energy demand growth (Reference Case 1), natural gas reaches approximately 25 quadrillion British thermal units

(QBTU) by 2010, a 25 percent increase from the 1991 level. This growth represents supply, transportation, and demand in economic equilibrium at natural gas wellhead prices that rise gradually by 2010 to about $3.50 per million BTU (MMBTU [1990$]). Under the scenario with low energy growth (Reference Case 2), natural gas maintains its relative market share with 7 percent growth by 2010. The wellhead gas price required to balance supply and demand in this case is projected to rise to about $2.75 per MMBTU (1990$) by 2010.

As a consequence of selecting this long-range focus for the study, short-term fluctuations around these trends are not addressed. Some price and volume volatility is natural, especially as industry moves through various transition periods. New risk allocation approaches using freely negotiated contracts rather than regulation will allow both the industry and its customers to handle volatility more effectively than in the past. As the changes foreseen and recommended in this study take hold, a more effective, competitive, and stable industry will emerge.

There are significant opportunities for natural gas to increase its share of the nation's energy consumption. However, all industry participants will have to work hard to continue providing quality service to existing customers and to address and overcome several obstacles with potential new customers. Increasingly, industry participants understand and are accepting the responsibility of addressing customer concerns and believe all obstacles can be overcome.

The results from the study are contained in the findings and recommendations that follow.

FIRST KEY FINDING

NATURAL GAS IS AN ABUNDANT DOMESTIC RESOURCE AND CAN BE PRODUCED AND DELIVERED AT PRICES THAT ALLOW BOTH EXPANSION OF THE MARKET AND CONTINUED DEVELOPMENT OF THE RESOURCE

Availability of Natural Gas Supplies

The United States has a vast and diverse natural gas resource base and estimates of the recoverable portion continue to grow with production experience and technological advances. The NPC concludes that this trend is likely to continue through at least the 2010 time horizon of this study, and estimates the technically recoverable resource at 1,295 trillion cubic feet (TCF) for the lower-48 states alone. Some 600 TCF of this gas is expected to be recoverable at wellhead prices of $2.50 per MMBTU (1990$) or less. However, production of this gas occurs over an extended period of time and, to satisfy a growing demand, other portions of the resource will need to be developed concurrent with the production of the less expensive gas.

Characterization of the Natural Gas Resource Base

The natural gas resources represent a diverse mix of opportunities (Table 1). Substantial

TABLE 1

NATURAL GAS RESOURCE BASE FOR THE LOWER-48 STATES (Trillion Cubic Feet)

Proved Reserves	**160**
Conventional Resources	
Reserve Appreciation	203
New Fields	413
Subtotal	**616**
Nonconventional Resources	
Coalbed Methane	98
Shales	57
Tight Sands	349
Other	15
Subtotal	**519**
Total Resources	**1,295***

*Technically recoverable resource base as of January 1, 1991, assuming that current access moratoria expire as scheduled and incorporating technology advancement through 2010. Assuming various price levels, with current and advanced technology, yields the following total resource estimates:

	Recoverable Resource Base (TCF)	
Price (1990$)	1990 Technology	2010 Technology
Unspecified	1,065	1,295
$3.50/MMBTU	600	825
$2.50/MMBTU	400	600

reserve growth and exploration prospects remain in conventional, historical producing areas, and there is important potential in new areas such as the increasingly significant Norphlet trend in the Gulf Coast Basin. Nonconventional resource opportunities include coalbed methane, shale gas, and gas in tight sand formations in major basins throughout the United States.

Figure 1 illustrates the dynamic, growing nature of the recoverable resource base. The 160 TCF of currently proved reserves represent, and should be perceived as, an inventory ready to contribute to near-term production. The proved reserves are backed up by another 1,135 TCF of resources that can supplement and replace the proved reserves as they are produced, given sufficient price and technology growth. The inventory of proved reserves is expected to remain at an approximate 10 year supply, a level that has been the industry norm for the past 15 years.

A significant portion of the resource base is currently inaccessible due to leasing moratoria on the Outer Continental Shelf (OCS); is restricted in wilderness areas, marine sanctuaries, National Parks, and Fish and Wildlife Service lands; and is subject to other *de facto* administrative moratoria. The full potential of these areas will not be known until access is granted. The reference scenarios assume there will be no access to these OCS areas until the current moratoria expire, with no production until after the year 2005, despite high prospectivity and the potential for significant low cost supply.

The costs associated with converting the natural gas resource to producible supplies are dependent on, among other things, the type of resource being developed, technology advancement rates, overall industry activity levels, and access to prospective acreage both onshore and offshore. Figure 2 shows future gas supplies under various wellhead price assumptions. These estimates are calculated from the model runs and include both domestic resources and available imports. While these calculations are subject to certain assumptions, including the rate of potential demand growth, producer response to market signals, and uncertainties in the description of the resource base itself, the results are believed to be indicative for the range of prices shown. At an average wellhead price of $1.50 per MMBTU (1990$), a 19 TCF (20 QBTU) supply level cannot be maintained. Prices that increase gradually to $3.50 per MMBTU (1990$) allow supply to grow with demand to 24 TCF (25 QBTU) annually.

Annual oil and gas expenditures for the producing industry have averaged $35 to $40 billion (1990$) over the past few years. This is comparable to the level of expenditure in the mid-1970s and about half of the peak expendi-

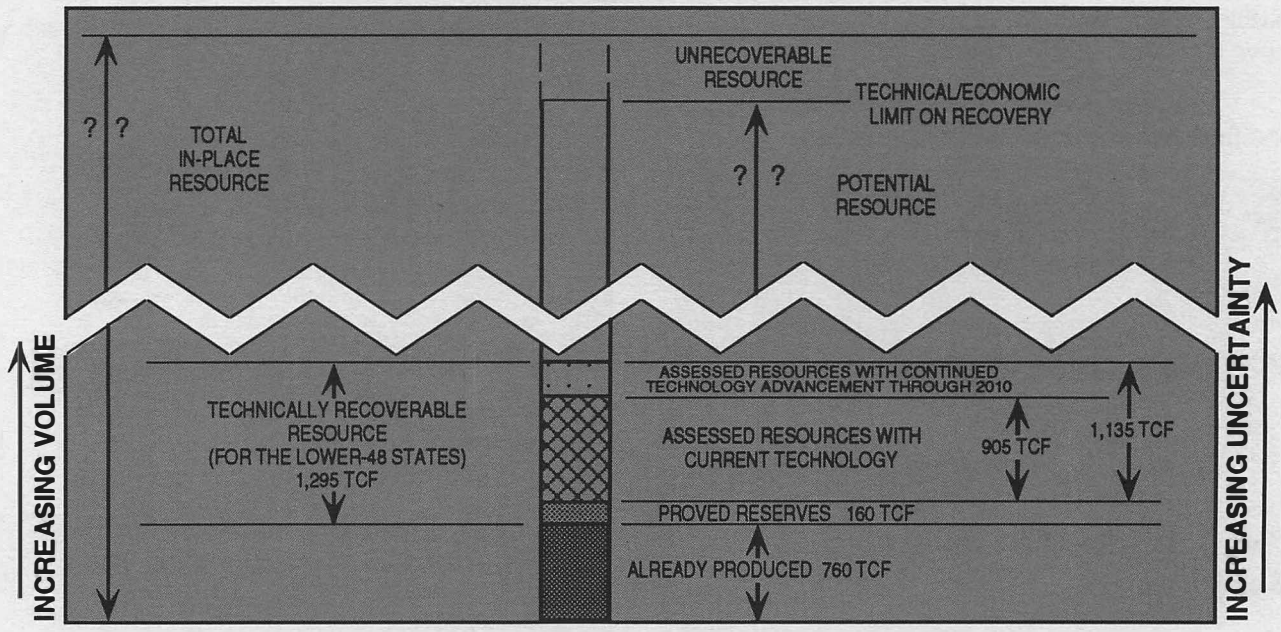
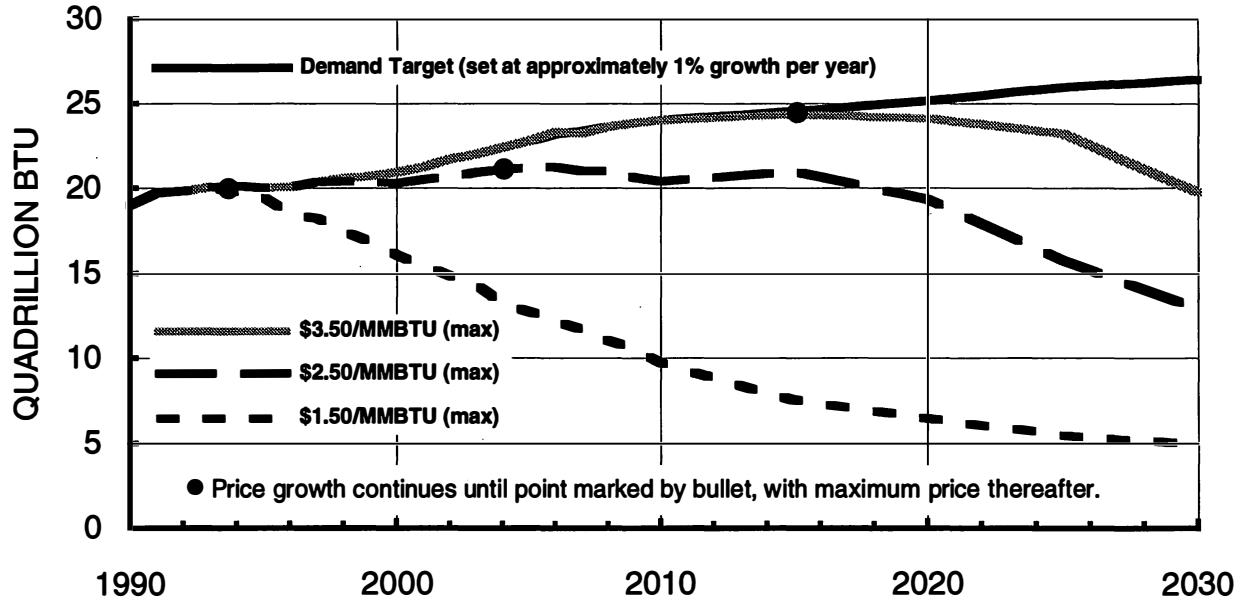


Figure 1. Schematic of Natural Gas Resource Base.



NOTES: 1. Assumes technology advancing throughout the period.
2. Prices are in 1990$ per million BTU for Texas Gulf Spot.
3. Demand target fully satisfied through 2030 at prices which do not exceed $4.50/MMBTU.

Figure 2. Long-Term Gas Supply Potential at Various Maximum Wellhead Price Levels.

ture years in the early 1980s. For Reference Case 1, where domestic production increases to over 20 TCF by the year 2010, investment levels are projected to increase gradually over the next 10 years and average about $60 billion (1990$) annually during the 2000-2010 time period. Lesser increases are expected for Reference Case 2, which projects annual investments remaining below $50 billion (1990$) throughout the study period.

As shown in Figure 3, the "ultimate" recoverable resource base grows with time and partially offsets the cumulative production, with a substantial resource base still available in 2030. It is also possible, of course, that time and technology will open the door to higher levels of recovery and new natural gas resources that are known to exist but have not been included in the current assessment—just as the coalbed methane, shale, and tight sand resources were not included in assessments made 20 to 30 years ago.

Impact of Supply Technology

Technology advancement has a significant impact on supply availability through dissemination of knowledge, mitigation of cost increases, and improved exploration and recovery processes that allow the industry to find and produce more gas economically. The results of an analysis of drilling costs revealed that during the past two decades, technology advancement has acted to reduce drilling costs by almost 3 percent per year below what they would have been in the absence of the advancing technology.

The rate of technology advance appears to be accelerating, with more effect in the 1980s than in the 1970s. As reflected in the 1,295 TCF recoverable resource estimate, the contribution of technology is expected to increase the lower-48 recoverable natural gas resource base by more than 200 TCF between 1990 and 2010. This rate of growth is consistent with that experienced during the past 20 years.

A sensitivity analysis indicated that if the rate of advancement of supply-related technologies could be increased by 25 percent over what was included in the moderate energy growth scenario, average wellhead prices could be as much as $0.50 per MMBTU (1990$) less than in the scenario projection. As a result, gas consumption would be encouraged, particularly in the industrial and electric utility sectors. The net value of this wellhead price reduction

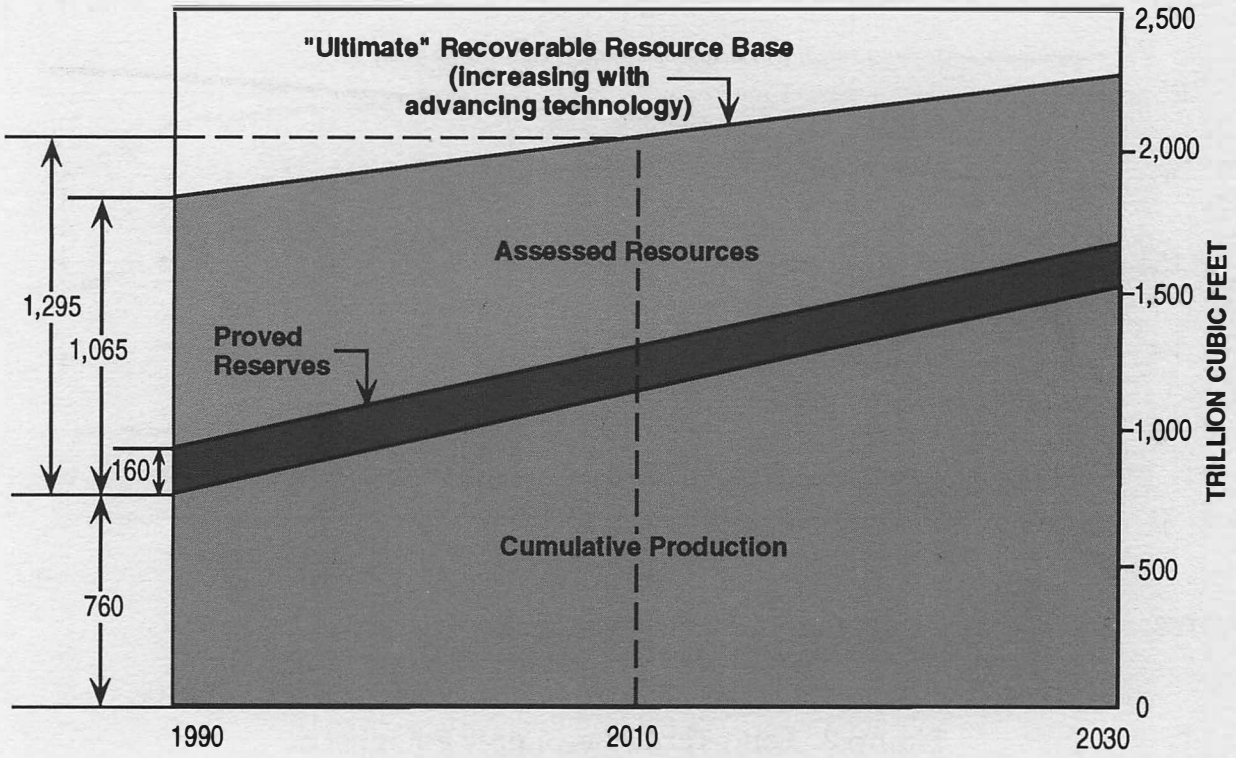


Figure 3. Gas Resource Base.

through 2010 would likely exceed $50 billion in total reduced costs to gas customers. Net imports of gas and residual fuel oil would also be reduced for additional savings to the nation. Conversely, if technology advances less rapidly than assumed in the calculations, an opposite impact would likely occur.

Impact of Environmental Compliance Costs on Supply Availability

In the NPC Reference Cases, the level of exploration and production (E&P) environmental compliance costs is based on a projection of requirements under the 1990 Clean Air Act Amendments, the Safe Drinking Water Act, and pending Resource Conservation and Recovery Act and Clean Water Act reauthorizations. This projection assumes the reasonable application of additional new rules under these regulations and results in compliance costs that continue to rise at a pace somewhat below the historical rate. By 2010, these additional costs reach $750 million (1990$) per year, or an increase in overall gas-producing costs of about 10 percent.

A sensitivity analysis was made of the impact of higher compliance costs if more cost-effective solutions are not found for future environmental regulations. In this sensitivity analysis, compliance costs grow to $3.5 billion per year in 2010. Over the period, the potential increase in costs exceeds $30 billion, additional to the $10 to $12 billion calculated for the Reference Cases, and results in 2010 production of 2 to 2.3 TCF less than the Reference Cases (10-12 percent of current annual supply) with a cumulative reduced production of up to 20 TCF over the period. The magnitude of these potential impacts highlights the need for government and industry to work together to develop more cost-effective solutions to environmental problems.

Potential Imports of Natural Gas

An assessment was also made of natural gas available from sources outside the lower-48 states. The Canadian resource base was analyzed, including estimates for the potential of nonconventional gas supplies similar to those in the United States. Model studies indicate that imports of gas from Canada are likely to continue to increase in the future and could possibly reach a level of 3 TCF or more per year, dependent, of course, on domestic demand for gas in Canada and the absence of trade restrictions. Mexico is expected to continue to be a net export market for U.S. producers over the next 10 years, but could become a

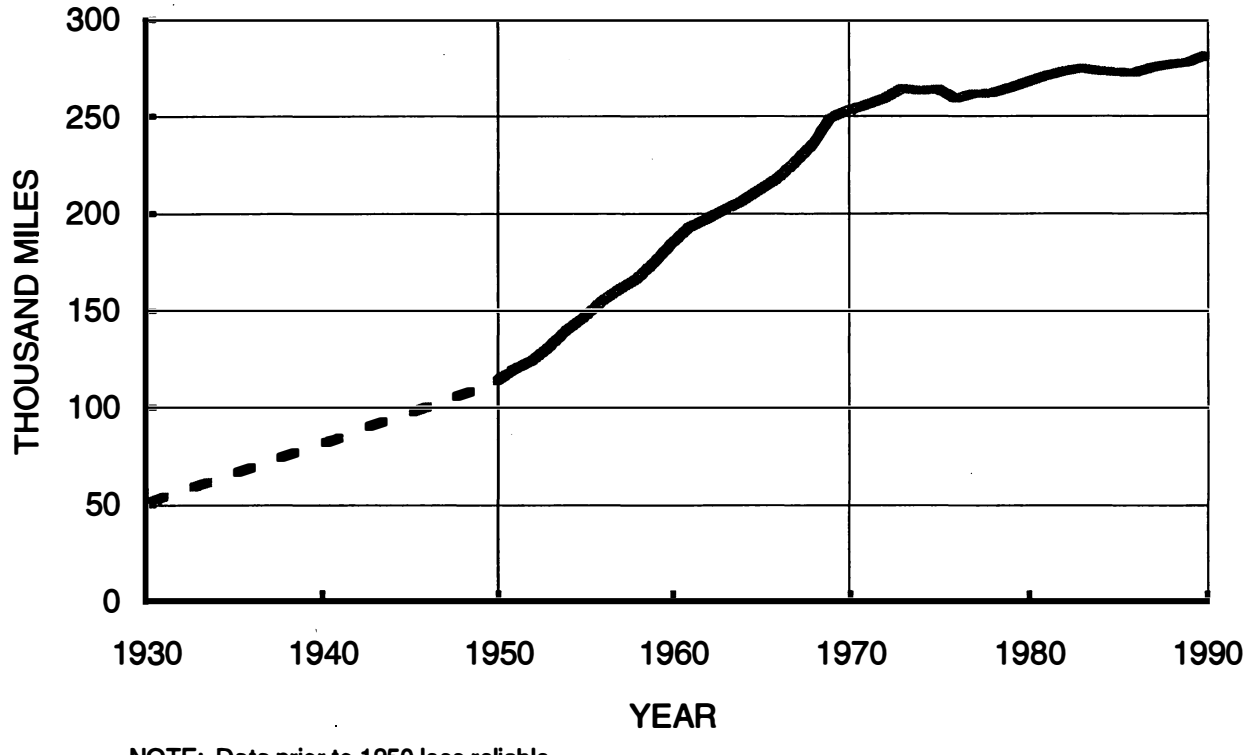
supply source if economic conditions supported development of Mexico's substantial resource base. Imports of liquefied natural gas (LNG) are likely to remain low under the assumptions of the two scenarios used in the study. Similarly, calculated price and demand levels appear to be inadequate for developing the Alaskan North Slope gas resources or the northern frontier gas in Canada for domestic consumption prior to 2010. Potential Canadian, Mexican, and Alaskan supply, as well as LNG, are also backed by large resources, although the domestic demand in these areas will be a competing market for the available supply.

Natural Gas Transmission and Storage

For natural gas to serve effectively the potential demand markets, the industry requires an efficient and reliable transportation and storage system. A critical analysis of the current system led to the conclusion that it can support a growing U.S. natural gas market served by a variety of supply sources. Although the consumption of natural gas in the United States peaked in 1972 at 22.1 TCF, the transmission and storage system has continued to expand due to geographic shifts in supply and demand (Figures 4 and 5). Today there are more than 280,000 miles of gas transmission pipeline and approximately 8 TCF of storage capacity.

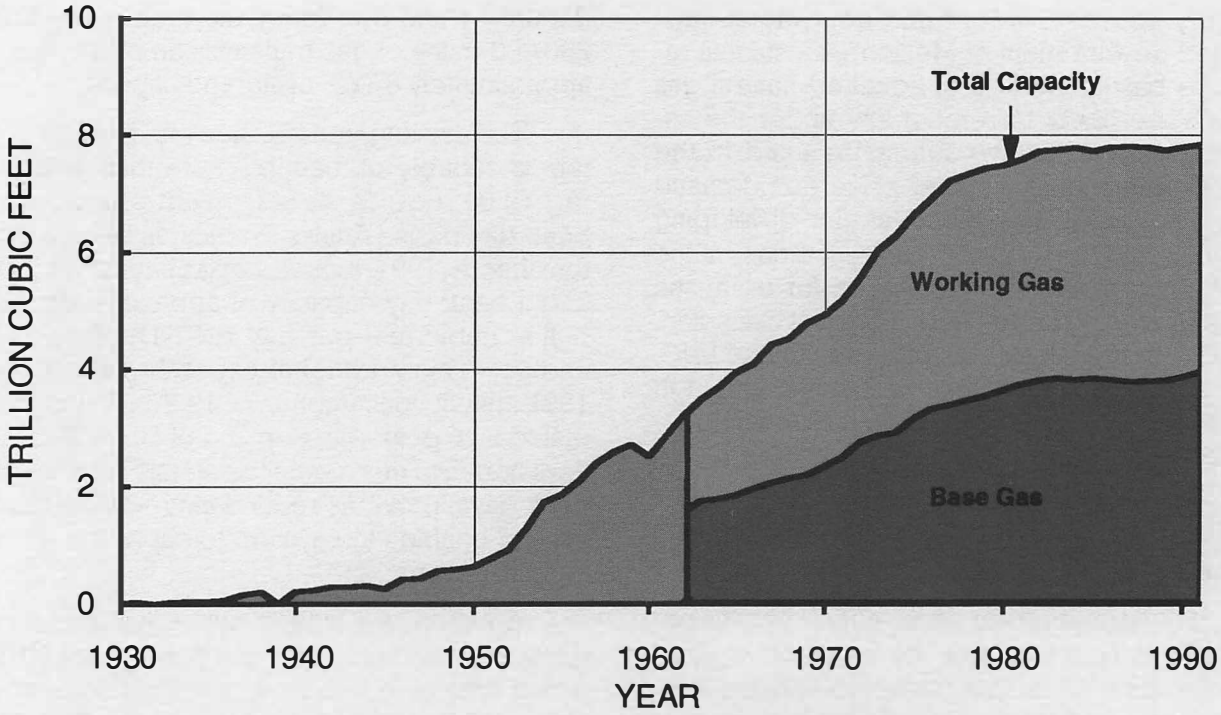
The existing transmission and storage system is capable of meeting more than its existing firm requirements on an annual and peak-day basis. Analysis indicates that the system had a 1991 annual capability of 24 TCF and a peak-day capacity of approximately 120 billion cubic feet per day (BCF/D) (Figures 6 and 7). This additional capability above the 1991 annual consumption of 19.2 TCF, and estimated firm peak-day demand of 102 BCF/D, allows non-firm customers to use this capacity on peak days, provides redundancy, adds reliability, and enables the system to support a growing U.S. gas market.

A significant shift is expected in natural gas supply and consumption patterns by 2010, which creates a need for construction of new transportation and storage facilities. With the anticipated decline in production from the Southwest Central region, additional transmission and storage capability will be required to move gas from the North Central region and from Canada to neighboring regions, and to move gas into the Northeast and California regions. The expenditures anticipated for this



NOTE: Data prior to 1950 less reliable.

Figure 4. Miles of Natural Gas Transmission Line.



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

Figure 5. Underground Natural Gas Storage Capacity–1930-1991.

investment are comparable to average total industry expenditures over the past 20 years and should not be a major constraint to future industry growth.

Impact of Higher Efficiencies on Delivered Gas Costs

The NPC believes that industry must take advantage of every opportunity to increase efficiencies over the entire natural gas system, from production through delivery, including transaction costs across each segment of the system. In order to illustrate the effect of possible increased efficiencies, an analysis was made of the impact of reduced costs on just a portion of the system. For simplicity's sake, the transportation system was selected as the example; however, a similar analysis would be applicable to the other sectors of the natural gas system.

The NPC Reference Cases assume that higher volumetric throughputs and some efficiency improvements would approximately offset real increases in labor and fuel costs for transportation, resulting in a slight decline in overall costs in constant dollar terms. If an additional net cost reduction of 2 percent per year could be achieved, the calculated delivered gas cost in 2010 could be reduced by some $0.17 per MMBTU. These lower costs could stimulate nearly 2 TCF of additional gas demand (cumulative) over the projection period. Most of that demand was projected to be supplied from domestic reserve additions and production, at essentially no net increase in average wellhead prices. The lower delivered gas prices could result in a net savings to gas customers in excess of $30 billion over the period. This again emphasizes the importance of making every effort to increase efficiencies across the system and thereby reduce the delivered cost to the customer.

SECOND KEY FINDING

The Natural Gas Market is Increasingly Diverse, with New Challenges and Opportunities

The markets for natural gas are as diverse as the participants in the gas industry itself. The markets range from individual residential customers whose consumption can be as low as 30 thousand cubic feet per year, to large industrial facilities and power generation installations

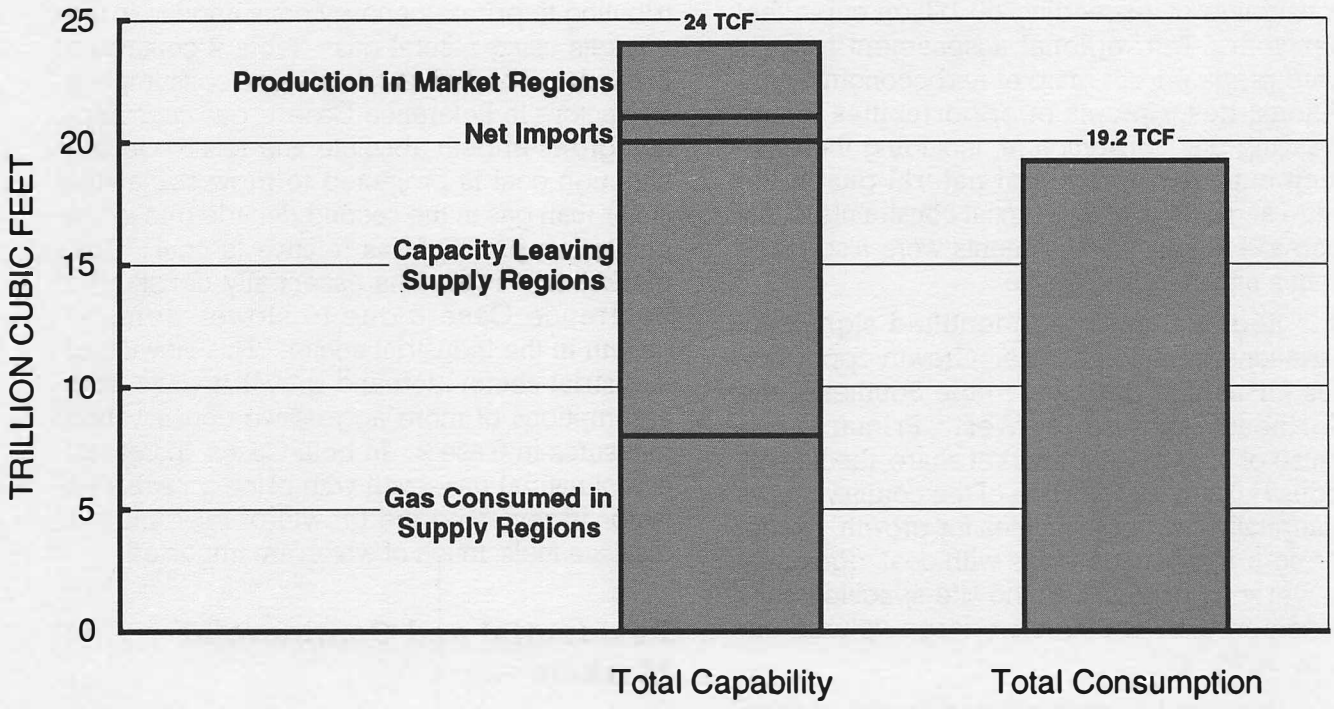


Figure 6. 1991 U.S. Transmission and Storage System—Annual Capability.

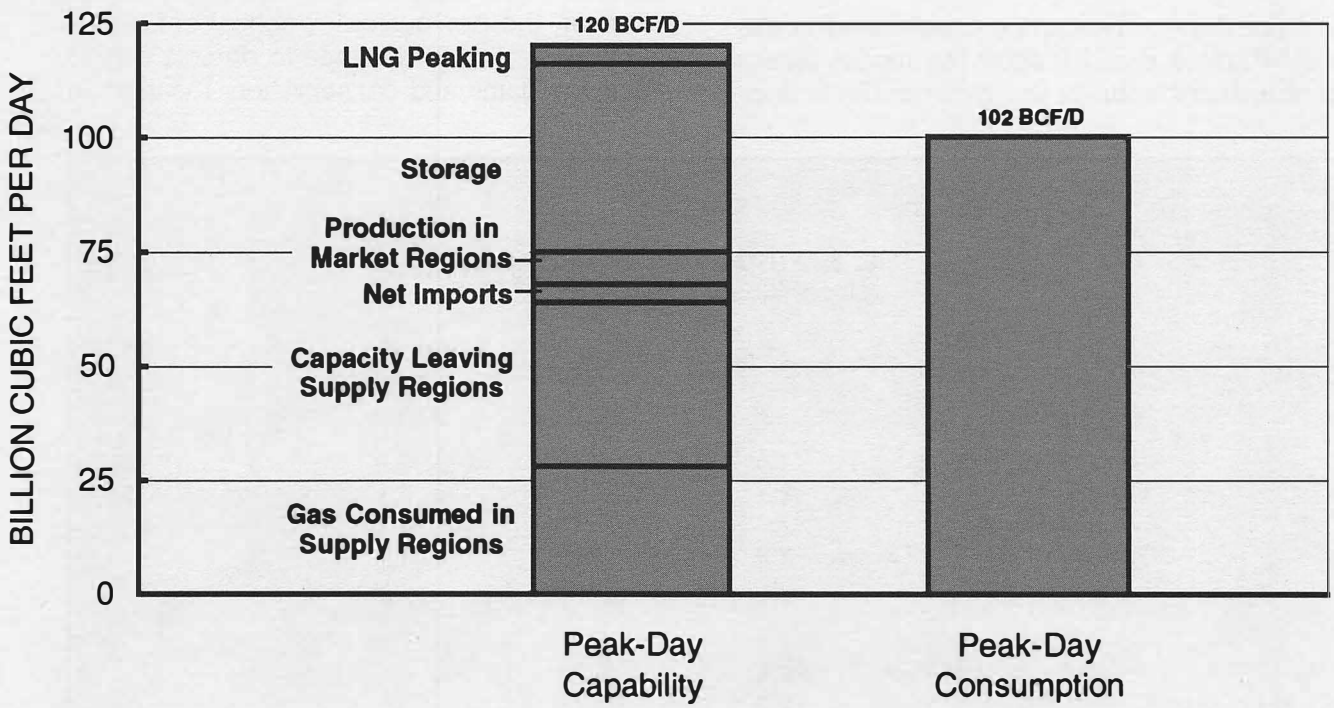


Figure 7. 1991 U.S. Transmission and Storage System—Peak-Day Capability.

consuming or exceeding 50 billion cubic feet per year. Ten regional assessment reports were prepared on: market and economic conditions; descriptions of opportunities for increasing gas consumption, including the environmental advantages of natural gas in the end-use sectors; and potential constraints to that increase. Similar assessments were also made from a national perspective.

Regional analyses identified significant variations by state and site. Growth opportunities for natural gas exist in the Southeast, the Northeast, and the Far West. Primarily because of high existing market share, the heavily industrialized mid-portion of the country shows marginally low opportunities for growth, except for co-firing of natural gas with coal. Proximity to fuel sources is one of the site-specific issues considered by prospective large volume energy customers.

Improved energy efficiency and conservation (stimulated in part by state integrated resource plans, environmental considerations, building efficiency requirements, and appliance efficiency standards) are impacting gas and electricity demand. Within this changing market, natural gas competes with coal, oil, electricity, and renewables.

For the two Reference Cases used in this study, Figures 8 and 9 show the model results for the distribution of the different fuels contributing to primary energy consumption in the markets using natural gas. Table 2 contains a breakdown of the calculated gas consumption by sector. In Reference Case 1, gas consumption grows in both absolute and relative terms, although coal is projected to grow somewhat faster than gas in the second decade due to the increasing price of gas relative to coal. Gas' market share remains essentially constant in Reference Case 2 due to slower demand growth in the industrial sector. This slowing of industrial sector demand growth results from assumptions of more aggressive conservation measures in Case 2. In both Cases, increased use of natural gas, even with price growth, is a factor in reversing the growth of residual and distillate fuels, much of which are imported.

Residential and Commercial Markets

The residential and commercial markets form the backbone of the natural gas industry. Natural gas is used in some 55 percent of all single-family dwellings, varying by region. Extensive efforts to extend service areas through aggressive marketing of gas services and technologies are expected to increase the total number of residential customers by 2010. However, the per customer annual consumption is projected to continue to decline due to efficiency gains and conservation, resulting in

TABLE 2

LOWER-48 NATURAL GAS CONSUMPTION
(Quadrillion BTU per Year)

End-Use Sectors	1990	Reference Case 1 2010	Reference Case 2 2010
Residential	4.5	4.9	4.7
Commercial	2.7	3.5	3.1
Industrial	7.0	8.9	6.1
Electric Utility	2.9	5.4	4.9
Total End Use	**17.1**	**22.7**	**18.8**
+ Lease/Plant Fuel	1.1	1.3	1.1
+ Transmission Fuel	0.6	0.9	0.7
+ Exports/Misc.	0.2	0.2	0.7
Total Consumption	**19.0**	**25.0**	**21.3**

Note: Totals may not agree due to rounding.

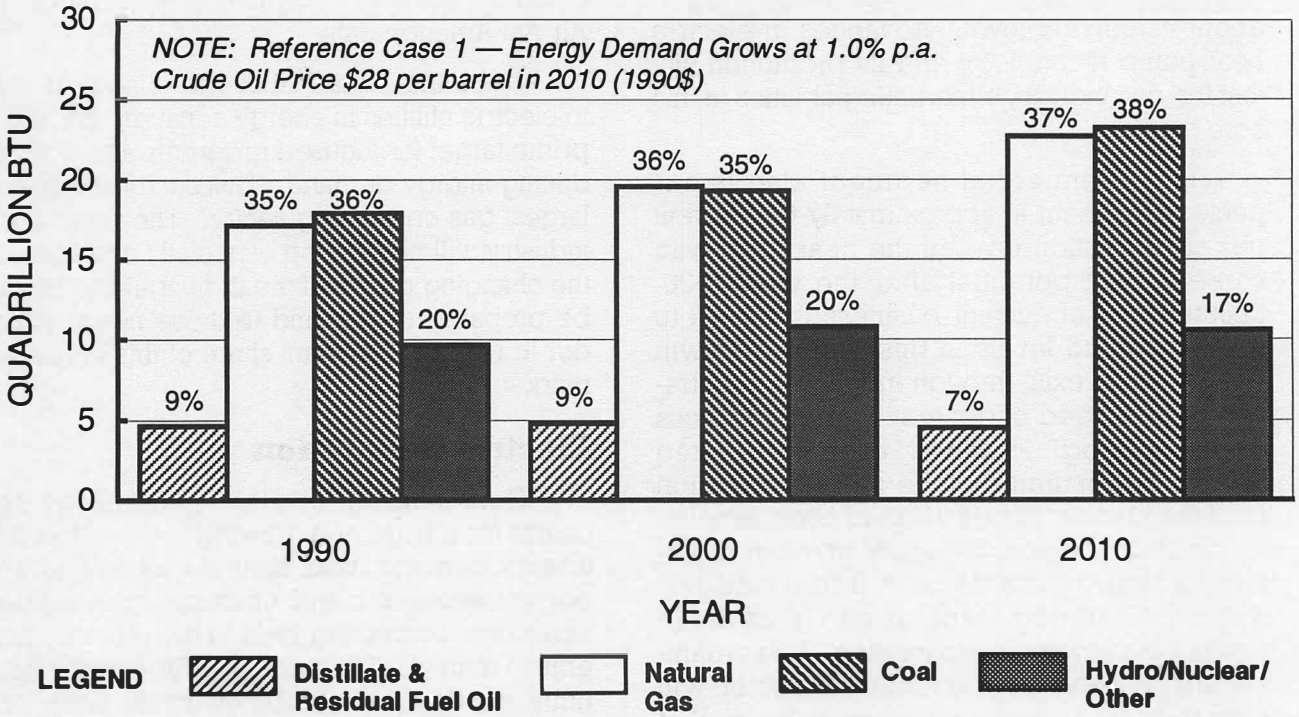


Figure 8. Primary Energy Consumption and Market Share—Reference Case 1
(Excludes Coking Coal, Oil Feedstocks, and Liquid Transportation Fuels; Gas Data Exclude Lease/Plant Fuel, Transmission Fuel, and Exports.)

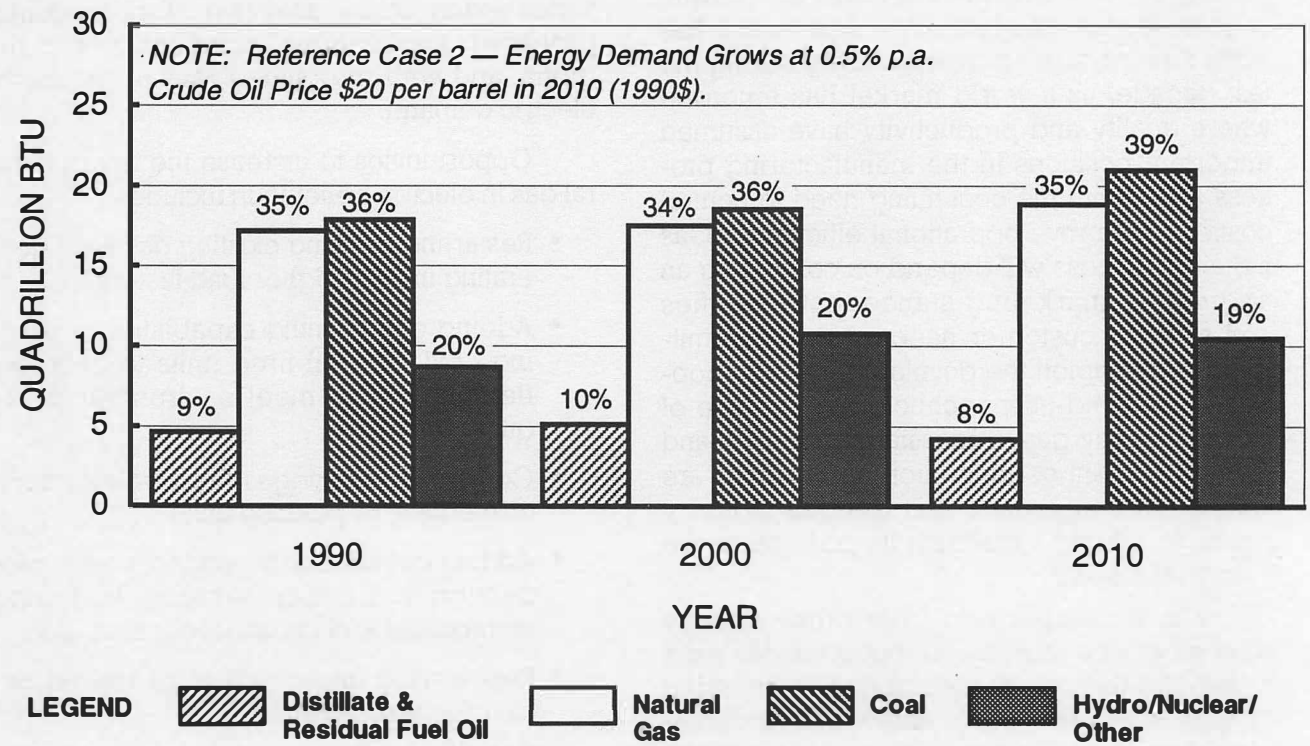


Figure 9. Primary Energy Consumption and Market Share—Reference Case 2
(Excludes Coking Coal, Oil Feedstocks, and Liquid Transportation Fuels; Gas Data Exclude Lease/Plant Fuel, Transmission Fuel, and Exports.)

total residential consumption remaining at about its current level. Advances in electric heat pump technology and its promotion will test the gas industry's marketing abilities in this core market.

The commercial segment also is expected to remain at approximately the current gas consumption level in the near term with some growth potential after the year 2000. Maintenance of current business is critical to future demand levels in this sector. Growth opportunities exist through increased penetration of packaged cogeneration and advances in gas cooling. However, even the limited growth opportunities face stiff competition from the electric industry. In addition, emphasis on conservation, federally mandated efficiency improvements, and Integrated Resource Planning will limit growth in commercial energy consumption. The organizations serving the commercial sector will have to work diligently to maintain this market at its current level.

Industrial Market

The industrial market represents one of the largest potential market areas for growth, or loss, for the gas industry. This sector has gone through a major restructuring during the last decade, as a world market has emerged where quality and productivity have assumed important positions in the manufacturing process along with the continuing need to control costs and improve operational efficiency. Gas industry success will depend on combining an aggressive marketing stance that identifies and satisfies customer needs with a commitment to champion the development and adoption of gas end-user technology. The use of high-efficiency, gas-processing equipment and energy-efficient cogeneration applications are an essential approach that the gas industry needs to adopt to maintain its position in the industrial market.

While competition from other energy sources will be formidable, opportunities exist to expand the use of natural gas in emission control, waste recycling, and waste remediation. Also, a strong potential exists to convert existing industrial coal boiler operations to natural gas or co-firing. These actions could allow for the creation of valuable allowances that could be sold for compliance with the Clean Air Act Amendments.

Since the industrial sector is second only to electric utilities in energy consumption, it is a prime target for focused programs aimed at reducing energy demand. This sector is also the largest gas-consuming sector. The natural gas industry will need to be especially cognizant of the changing nature of the industrial sector and be prepared to respond to these needs in order to retain a dominant share of this important market.

Electric Generation

Consumption of electrical energy accounts for a large and growing share of the U.S. energy demand, with natural gas having important economic and environmental advantages over competing fuels in the electric generation market. Advanced gas-fired generating units, particularly combined-cycle units, are more efficient and less capital intensive than other alternatives, have lower non-fuel operating costs, and can be constructed with shorter lead times with smaller, economically sized units. The potential for natural gas to have an increased role in the electric generation sector varies widely among sites (e.g., distance from a pipeline), applications, companies, and regions, and with the overall rate of growth of electric demand.

Opportunities to increase the use of natural gas in electric generation include:

- Restarting or using existing gas-fired generating units at higher load factors
- Adding gas-burning capabilities in existing coal- and oil-fired units to gain fuel flexibility or to meet environmental requirements
- Constructing new gas-fired baseload, intermediate, or peaking units
- Adding gas-fired independent power production and self-generation, including commercial and industrial cogeneration
- Repowering uncompleted or retired nuclear generating units.

Results from the two NPC Reference Cases suggest impressive growth potentials for natural gas in electric generation. Major obstacles will need to be overcome, though, before

these opportunities can be converted to increased gas consumption. Among the more significant of these are:

- Competition from other energy sources, with the competitiveness of gas being dependent on the wide variation among sites, regions, applications, companies, and distances from pipelines
- Understanding factors affecting electric generators' fuel choices and responding to electric generators' concerns, needs, perceptions, and expectations
- Satisfying potential customers that the delivered price of natural gas, including the cost of gas transportation, will continue to be competitive with other energy sources and with potential demand-side measures
- Convincing potential customers that natural gas supplies will be available when needed and can meet their operational requirements.

A key assumption for any projection of gas demand in the electric generation market is the annual electricity demand growth rate. Annual gas consumption for electric generation could be lower due to demand-side activities and slower economic growth rates. Conversely, more vigorous economic growth assumptions can increase electricity usage, and thus, gas demand.

Natural Gas Vehicles

There are an estimated 30 million fleet vehicles in the United States and over one-third of these are located in ozone non-attainment areas as defined by the 1990 Clean Air Act Amendments. The Natural Gas Vehicle Coalition estimates that all U.S. fleet vehicles combined consume an equivalent of 2 TCF per year of liquid fuels. In the NPC Reference Cases, the penetration of natural gas by vehicle type and location was estimated to result in a consumption level of 140 BCF per year by 2010. A more optimistic natural gas vehicle market penetration and gas supply sensitivity case, with consumption levels increased to 640 BCF per year by 2010, indicated that the natural gas industry could supply additional volumes of gas to the natural gas vehicle market without adversely affecting other markets.

THIRD KEY FINDING

Increased Reliance on Competitive Market Forces Has Improved the Gas Industry's Ability to Serve Customer Needs in a Diverse and Expanding Marketplace

Information collected during the course of this study shows that the newly evolving natural gas market works. Market forces have been the primary drivers of change ever since the decontrol of wellhead gas prices and the Federal Energy Regulatory Commission (FERC) began open-access transportation with the introduction of FERC Order 436 in 1985. The subsequent increase in competition has resulted in lower delivered gas prices, increased availability of supply, and new service options for consumers.

FERC Orders 636 and 636A mandate nearly complete unbundling of pipeline gas sales from transportation services and is intended to foster competition for natural gas transportation and storage. Creation of a secondary market for pipeline capacity is an integral part of Order 636. This should further improve efficiencies by allowing capacity to be assigned to those who value it most, whether on a short-term or long-term basis. Such activity would serve another important function that has traditionally been lacking in the industry: clear market signals regarding the need for new capacity.

The expansion of value-added services being offered by the industry is additional confirmation of this new competitiveness. Today's market is rapidly evolving with resources and production being efficiently matched with customers on an ongoing, operational basis. Through the mid-1980s, the regulatory framework generally mandated that interstate pipelines aggregate gas supplies for sale to all customer groups. Under today's more open and competitive regulatory environment, gas supplies are being combined into economically and operationally viable packages by many different industry participants. The packaging of gas volumes at a market-clearing price is still evolving, and other services are

making natural gas much easier to acquire when and where needed.

Integral to the evolving service environment is access to data, from production through consumption. Electronic gas measurement, electronic bulletin boards, operational balancing agreements, pooling points, and other devices, both physical and contractual, have an important role in making it easier to provide gas in a responsive manner. Separate from the traditional industry segments offering various service options, a new role within the industry has emerged over the past ten years for "natural gas services providers." This category is broadly defined to include an array of companies within the industry that are moving beyond their traditional roles and providing a new variety of customized services aimed at meeting customers' specific needs. The ability of natural gas service providers to enter into a variety of contracts without threat of after-the-fact regulatory intervention, but being prepared to live with the consequences of their actions, is a key element in making these providers a vital part of the industry's future.

With this new gas marketplace, the customer's ability to buy its own supply and choose only the transportation and storage services it needs, along with the ability to reassign such services when not needed, provides substantial flexibility to select appropriate levels of risk. Supply contracts, together with transportation and storage service arrangements, provide a fundamental structure under which individual buyers can balance risk versus delivered gas costs, and under which sellers can secure gas outlets at optimum prices. In conjunction with a diversity of contract structures tailored to individual needs, the natural gas futures market can be used to help manage near-term risk. For example, producers can reduce their exposure by using futures to lock in prices for their gas several months in advance. Local distribution companies (LDCs) and other customers can purchase futures contracts to provide a ceiling for the price they pay for gas in later months.

Some industry participants have yet to take advantage of the opportunities made available to them in these markets. For example, LDCs face a unique problem in that state regulators must be convinced that long-term contracts, futures, options, and other diverse contract arrangements can be effective risk management tools, rather than highly speculative "gambles," as they are often perceived. In an effective market-based environment, LDCs, along with all industry participants, should be provided the opportunity to use these tools.

Gas industry participants often mention that federal and state regulatory uncertainty is a major impediment to industry growth. With parties willing to match their risk tolerance with costs and obligations, federal and state regulatory policy initiatives must continue to support the move toward contract-defined relationships. Similarly, gas providers and consumers must be allowed to be accountable for their contractual decisions in the marketplace, not in regulatory proceedings. Contract diversity, a regulatory climate that honors contract sanctity, and active financial markets that can be used to manage risk can work together to assure that each market participant attains the desired degree of reliability and security.

FOURTH KEY FINDING

The Gas Industry Faces Significant Challenges Requiring Proactive Steps by Industry and Government

The natural gas industry faces numerous challenges as it moves to increase the role that natural gas plays in meeting the energy and environmental needs of the nation. The challenges are diverse and include both real and perceived concerns that result both from past experiences of customers and from uncertainties about the changing industry.

Ignoring these challenges would be harmful to the prospects of the natural gas industry itself, as well as the national economy and the environment. The challenges for industry have been grouped into the following areas for discussion and recommended action:

- Reliability
- Customer orientation and marketing
- Behavioral issues.

Government policy and regulation can constrain the ability of industry to react to cus-

tomer needs. The NPC concludes that government and regulatory policy makers should minimize intrusion into markets where competition can exist, and weigh the additional costs of regulation in all markets. Accepting that there is a continuing, albeit more limited, role for governmental action in the natural gas market, the challenges to government fall into the following categories:

- Fostering choices that serve the public interest
- Promoting system efficiencies
- Reducing regulatory uncertainty.

In addition, both industry and government face significant challenges in the areas of: access restrictions, technology development and commercialization, and environmental regulation.

Challenges for Industry

Reliability Concerns

A long history of intense and changing regulation, accentuated by public and private underestimates of supply potential, has worked to suppress demand and perpetuate the prevailing oversupply situation. The recent downsizing in the domestic E&P sector and declines in drilling activity in North America are largely the result of this situation—rather than a lack of drilling opportunities—and the trend should be reversible in part if market signals are favorable. However, there is likely to be some lag and some continued price volatility due to the lead time inherent in many investment decisions in all phases of the business. Increasingly widespread and lengthening access restrictions and OCS moratoria compound the concerns as do ever more stringent application of environmental law to producer activity.

Additional reliability concerns arise from both real experience and perceptions. The history of the U.S. natural gas industry includes several cases where natural gas did not prove to be reliable **in the view of the customer,** e.g., the curtailments of the 1970s and the extraordinarily cold period in late 1989. The concerns of the natural gas consumers about reliability depend heavily on the type of customer served. Residential and small commercial customers have expressed little concern about reliability of supply, although they are concerned about potential price volatility. On the other hand, with curtailments and confusion during periods of regulatory change, industrial and power generation customers have had a less impressive experience with natural gas reliability; these sectors also represent the most promise for growth.

As the commercial interactions within the industry shift from a regulated to a contractual basis, some of these concerns should fade. While action has been undertaken recently to address reliability issues, such as the FERC/DOE Deliverability Task Force and the consideration by the Natural Gas Council of a Natural Gas Reliability Council, nevertheless the development of a set of reliable services designed to meet customer needs, and the marketing of those services, remain as serious challenges to the industry.

Customer Orientation and Marketing

The natural gas industry generally has not been sufficiently customer oriented. In the past, natural gas marketing consisted of passing a commodity down the chain in the general direction of the end user, where all the commercial relationships had extensive regulatory limitations and natural gas was "marketed" by taking orders. Now, many natural gas companies are playing integrated energy service roles all along the line from producer to end user. Companies that can add value to the process need to develop additional marketing capabilities that are critical to a successful natural gas industry future. Full development of possible services requires that all segments of the industry explore new and more effective ways of using talents, facilities, and experience.

Behavioral Issues

The behavioral concerns are more difficult to address as they tend to influence actions in all industry segments. Many customers believe that the regulated sectors of the natural gas industry have little or no incentive to become more efficient. This perception arises from the belief that with regulation, economic incentives are masked and that regulatory "game-playing" is rewarded. Competition in the context of an open and competitive market creates good results for customers. Unnecessary fighting by industry participants

in the context of regulatory hearings and judicial proceedings, and without regard to customer reactions, sends adverse signals to customers. Such behavior conveys the impression that different segments of the natural gas industry cannot work together, and the customer will be convinced that reliable energy services cannot be developed.

In the natural gas industry of the past, regulatory policy shaped the destiny of the industry. In the emerging, more competitive market, individual businesses must develop their own vision of the future. It should not be inferred from the above that all of industry's challenges come from its regulated history; ultimately it is industry's own behavior that has the greatest effect.

Challenges for Government

Fostering Choice

The findings from this study support the premise that a competitive gas industry is developing, that it can function effectively and provide a range of services and products, and that this can work to the benefit of informed customers who may choose the terms and prices that best meet their needs. Correspondingly, regulatory policy should be directed toward increasing the number and quality of choices available to buyers and sellers without unnecessarily interfering in the consequences of those choices.

A robustly competitive natural gas industry will increase consumer satisfaction. Also, a competitive market will allow consumers and service providers, through mutual agreement, to make individual decisions about managing and allocating risks and associated costs. Because the exercise of individual choice is integral to achieving the public interest, regulators and policy makers should not substitute their opinion of risk tolerance for that of the customer.

Promoting System Efficiencies

Efficiency improvements, innovations, and new value-added services are more likely to develop in a competitive market than in one that is regulated. Incentives may be required in the regulated environment in order to obtain these same benefits.

Reducing Regulatory Uncertainty

During a period of industry transition, particularly transition aided and encouraged by regulatory policy, the most important challenge to regulators is to be clear about the goals of regulatory change. Uncertainty that arises from regulatory change, exacerbated by a lack of clarity, can limit the efficient and effective development of markets.

Finally, as the industry develops the ability to operate more effectively and with greater customer orientation, regulators and policy makers will be challenged to exercise restraint during periods of price and supply volatility. The emerging industry will not look like the historical industry, and lessons learned from the past may not have direct application in the future.

Challenges for Both Industry and Government

Development and Commercialization of Technology

Technology's role in increasing natural gas supply and mitigating cost increases is a cornerstone of the findings of this study. For natural gas to fulfill its role in the United States' energy picture, the technologies related to its production, distribution, and consumption must continue to evolve.

The NPC supports the fundamental premise that funding for technology development and commercialization should come first from private industry using risk capital and responding to market signals with the benefits accruing to the investor in recognition of the risk taken. Of the $750 million of estimated 1992 investment in natural gas technology development, near two-thirds was provided by private industry. The Gas Research Institute and other associations accounted for about one-quarter of the total investment in natural gas technologies, while the federal government contributed about one of every eight dollars invested. The majority of private investment was directed toward increasing supply and reducing costs, where the market mechanism has generally proven to be capable of providing good direction and allowing this sector to recognize the benefits of its investment in the successful deployment of new technology.

In contrast, however, regulated companies traditionally use a rate-of-return methodology that provides little reward to shareholders for the rapid development, commercialization, or adoption of new technologies. The resultant funding for end-use technology development and its ultimate commercialization has thus been constrained. This is also due, at least in part, to the fact that end-use equipment manufacturers are generally fuel neutral, since they manufacture different models of the same appliances and equipment to use either gas, oil, or electricity. This includes U.S. auto makers, who are finding little profit motive to develop natural gas vehicles.

The gas industry's challenge for technology development and commercialization involves continued funding by the producing segment of the industry, increased incentives for investing in technology by the regulated segments, and justification for investments in commercialization of end-use technologies. Also, the low level of federal government spending on gas-related technologies, relative to other energy sources, suggests a need to reexamine the potential benefits of investments in this segment, particularly in light of the evidence that natural gas is an abundant natural resource with superior environmental qualities.

Environmental Regulation and Access Restrictions

This study examined the impacts of potential future environmental regulations and access limitations on the exploration, production, transportation, and storage of natural gas. The results of this analysis demonstrate a clear potential to limit the ability of industry to increase the production of natural gas as an important resource in the national energy mix. At the end-use sectors, however, there remain unfulfilled opportunities to increase the use of natural gas driven by environmental regulations aimed at solving the nation's air quality problems.

Within this apparent dichotomy, the challenge is for industry and government to work together to solve the pressing environmental issues facing the E&P and transportation sectors in a balanced and cost-effective manner. The opportunity is for industry to develop new markets and for improved air quality for the nation.

FIRST RECOMMENDATION

Federal, State, and Local Officials Need to Allow Competitive Market Forces to Continue to Develop and Work

To allow the competitive gas market to continue to develop and function effectively, actions are recommended that:

- Foster choices that serve the public interest
- Promote system efficiencies
- Reduce regulatory uncertainty
- Support development and commercialization of technologies that reduce cost and increase the choices available to the consumer
- Promote cost-effective environmental regulation and reduce access restrictions.

Fostering Choice

Policy makers and regulators need to more explicitly define public interest and establish objectives that include a clear identification of whose public interest is being furthered by individual regulatory or policy actions. This new definition of the public interest should emphasize the principles of competitive markets and consumer choice, while recognizing a continuing, although greatly reduced, role for regulation. Industry and regulators should continue the evolutionary process toward deregulation in competitive markets and should explore the potential for incentive regulation in those markets where competition has not been shown to exist.

- Where market forces are sufficiently robust to provide reasonable service choices, regulatory decision making should defer to market forces. For example, the FERC should eliminate the traditional tests for new interstate pipeline construction and parties should be permitted to allocate risk through contractual mechanisms.
- Regulation should refrain from unnecessarily restricting the number and quality of choices made available to the buyers and

sellers of energy services; neither should it interfere with the consequences of those choices.

- The FERC should continue to promote the development of robust secondary markets for regulated transport services with customers allowed to trade capacity rights in minimally regulated secondary markets.
- Regulators should consider new forms of incentive rate making, phased activities, and pilot projects to examine the feasibility of new, less intrusive, regulatory structures. Where continued regulatory oversight is required, rate ceilings should be emphasized over profit ceilings.
- State commissioners should evaluate and direct as appropriate the unbundling of LDC and intrastate pipeline services to further competition and consumer objectives.
- Gas procurement should be deregulated where competitive markets exist and buyers have equal access to competing gas supplies.
- State regulators should explore alternatives to traditional service obligations so that competitive service offerings may be developed. The benefits of and need for franchise protection for LDC services to certain market segments should be reviewed and reevaluated. State regulators should distinguish between captive and non-captive customers.
- Oversight of gathering systems at the state level may be indicated in isolated cases where abuse of market power may prevent access, but regulation is not appropriate where sufficient competition exists.
- The regulation of safety and minimum service standards at state and federal levels should remain intact.

Improving System Efficiencies

Commissions should consider different forms of incentive regulation that lead to increased efficiency, improved productivity, and reduced costs, and encourage new and innovative services that are responsive to customer needs.

- Cost-of-service and rate design principles should be used that avoid cross subsidies among types of services and classes of customers.
- Current programs and policies should be examined at both the state and federal level to eliminate unnecessary costs across the entire system, including environmental costs or restrictions that are not commensurate with the ultimate benefit to the consumer.
- State regulators should adopt a fully integrated approach to energy resource planning, which recognizes the environmental benefits of natural gas.

Reducing Regulatory Uncertainty

Uncertainty about rates and access to transportation capacity makes it difficult for customers to make decisions regarding future energy needs. A regulatory system needs to be developed that allows the affected parties to have a knowledge of and confidence in natural gas prices and transportation rates at the time a transaction occurs, without the danger of those prices or rates being disturbed by lags in regulatory decision making.

- Regulators should determine the rate treatment for new facilities in advance of construction.
- Regulators must no longer permit rate changes that have a retroactive impact.
- Regulatory proceedings that remain necessary must be timely and efficient with procedures that guarantee completion within a reasonable time frame.
- Individual rules and regulations, as well as authorizing statutes, must be reviewed to remove impediments to real-time informed choices and educated risk assumptions by natural gas sellers, transporters, and customers.
- Regulators should account for the effects of their regulatory decisions on all sectors of the industry, in order to prevent undesirable side effects, and for consistency with overall national policy objectives.

Technology Development and Commercialization

Consideration needs to be given at the federal and state levels for support of the de-

velopment and commercialization of new technologies where the results can be reasonably expected to foster additional choices for the consumer or reduce the consumers' ultimate cost of service.

- The federal government should re-examine its natural gas research, development, and demonstration (RD&D) effort in light of the evidence that natural gas is an abundant natural resource whose increased use could provide environmental and balance-of-trade benefits.
- Serious consideration should be given to increasing the annual federal funding level for gas-related RD&D, including development of cost-effective environmental compliance technology, to about $250 million, consistent with other recent recommendations.
- A review should be initiated by the Department of Energy, in concert with industry and regulators, of limitations on end-use commercialization efforts caused by a cost-based regulation system.
- The federal RD&D program should examine new ways to sponsor cooperative, joint research projects with industry participants, particularly independent producers.
- Coordination efforts should continue to be increased between the DOE and industry organizations and associations.

Environmental Regulation and Access

Government agencies at all levels should create a balance between costs and benefits in the legislative and regulatory process for environmental and access issues that affect the natural gas industry. A balanced approach will ensure protection of the environment while moderating the financial impact on industry and providing the necessary access to the available resources.

- The federal regulatory moratoria should be extended for the review and modification of the current regulatory and permitting process to ensure a technically based and balanced approach to designing and implementing new regulatory requirements. These revisions should specifically include the net environmental benefits of natural gas.
- Minimize and/or alleviate access restrictions on industry by:
  - Developing an approach to leasing and permitting that will assure access to prospective acreage for prudent, environmentally sound exploration and development programs. This includes a re-evaluation of acreage currently under moratoria as their terms expire.
  - Modifying federal leasing programs so that successful bids that are based on accepted environmental guidelines would be issued with drilling permits.
  - Expediting the review and approval process for new pipeline projects at the federal, state, and local levels without diluting substantive environmental protection.
- Government agencies at all levels should move forward cautiously with the use of environmental externalities until they have carefully researched methodologies and have developed a well thought out approach for implementation.

SECOND RECOMMENDATION

Industry Needs to Make the Market Work

If natural gas is to play a more significant role in the U.S. energy mix, it is imperative that industry base its practices on the findings that the resource base is not limiting, that gas supplies can be delivered at competitive prices on a timely and reliable basis, and that opportunities exist to increase gas consumption in a variety of markets. Regulators and other policy makers are poised to help the competitive natural gas market work, but it is the responsibility of industry to make it work and perform to the benefit of the consumer, the environment, and the nation.

Reliability

Natural gas reliability is of concern to all sectors of the industry and in particular to the

electric utility and industrial customers, who have unique operational requirements. Concerns encompass price volatility as well as supply and pipeline deliverability. Reliability has different meanings to different people and perceptions are often as important as facts and analyses. It is, therefore, imperative that industry openly address the reliability issue to ensure that natural gas is best able to compete effectively in the nation's energy markets.

The NPC believes that industry should give serious consideration to the formation of a Natural Gas Reliability Council and recommends support for the scoping study that is being performed by the Natural Gas Council to establish the requirements for such an organization. The purpose of the Reliability Council would be to improve reliability of natural gas service and increase customer confidence in natural gas. Its mission would be to provide facts, analysis, and recommendations relevant to improving the reliability of gas service.

Other actions should be undertaken independent of the formation of a Natural Gas Reliability Council to reduce the customers' concerns over reliability:

- The findings from this study should be used by industry to enhance confidence in the nation's current supply and delivery systems.
- Transmission companies and LDCs should undertake efforts to coordinate maintenance and downtime across industry segments to minimize potential interruptions in gas deliverability.
- Producers should insist on the maximum possible discretion in managing production in relation to swings in market demand and prices, while recognizing that states have an obligation to protect correlative rights and prevent waste.

The consuming sectors must be able to make decisions based on economics, service, and environmental requirements with full confidence in the reliability of natural gas being available when, where, and under the terms specified by the contracting parties.

Customer Orientation and Marketing

A commitment to the customer is essential to achieving growth in market share. This will require a dedication to being customer oriented and providing the products and services appropriate to the needs of the customer.

- 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."
- It is imperative that LDCs continue aggressive programs to increase demand and maintain market share in existing residential, commercial, and base load industrial sectors.
- Other industry segments should support and leverage LDC efforts by providing a full range of services designed to meet customers' gas acquisition needs. Recognition and support should be given to the new role of natural gas service providers.
- Industry needs to focus effort on demand growth in the major market opportunity areas (e.g., electric power generation, natural gas vehicles, and gas cooling) as well as identifying and maximizing opportunities in niche markets (e.g., gas engine drive, environmental emissions control, gas heat pumps, and gas process cooling).
- The natural gas and power generating industries must cooperate, coordinate, and compromise to make the transporter/customer relationship work.
- Mechanisms must be devised to make it easy for customers to buy natural gas. Innovative contracting practices should continue to be offered, supported by a regulatory environment that honors contract sanctity. The development of emerging markets (financial, transportation, and others) should be encouraged.
- Industry should support the creation of additional market centers as mechanisms to promote better access and improved reliability of natural gas services.
- Better methods need to be developed to communicate to customers the availability of transmission and storage capacity.
- Efficiencies must be improved across the entire natural gas system, including re-

ducing regulatory compliance costs, so natural gas can continue to be delivered to the customer at the lowest possible cost.

Technology Development and Commercialization

The continued development and commercialization of technology is fundamental to maintaining and expanding market opportunities, increasing the supply of natural gas to those markets, and reducing gas cost to make it even more competitive with alternative energy sources.

- Each segment of the gas industry must ensure that gas technology is a priority for its own facilities and operations to provide the demonstration sites necessary for commercialization efforts and to demonstrate its belief in these technologies.
- Industry must continue to invest in its own development programs and should be willing to participate with government in appropriate jointly funded programs.
- Industry segments must recognize the inherent limitations of a regulated structure and cooperate with policy makers in devising mechanisms that allow the benefits of investments to flow to the providers of the risk capital.

Environmental Regulation

Industry must play an active role in developing environmental data on natural gas, increasing the public's understanding of the positive benefits of natural gas, and developing new and innovative strategies for dealing with environmental issues.

- Initiate an industry/government project to develop a methodology for doing cost-benefit environmental evaluations and document the results in a "How To" manual for industry, government, and public use.
- Gather the technical information and knowledge necessary for the natural gas industry to develop a strategy regarding environmental externalities.
- Initiate an industry/government project to develop methodologies and tools for education and communication efforts that explain the role of natural gas in a balanced but comprehensive energy conservation, pollution prevention, and energy development program.
- Improve the integration of environmental issues into strategic business planning and decision-making processes.
- Develop direct business opportunities for the natural gas industry by developing or adapting products, processes, and services to meet the current and future needs of the American consumer.

Leadership

Finally, leaders in all segments of the natural gas industry must commit to a concerted, ongoing, and consistent effort that focuses on the unique attributes of natural gas and its ability to deliver superior value to customers.

First and foremost, a consistent and coherent vision must be developed for the future direction of the industry.

Second, the industry needs to educate both itself and its customers on the facts about natural gas. Information should be made available on (a) the ability of supply to economically and reliably meet the needs of the consumer, (b) the environmental and life-cycle cost advantages of natural gas, and (c) the opportunities for improved customer and service orientation.

Third, industry must improve communication and coordination with its customers in order to best satisfy their objectives. The joint task groups that were formed recently between the natural gas and electric generation industries should be continued and expanded to include other customer classes. Industry also needs to encourage federal and state policies and guidelines that explicitly recognize the potential of natural gas to enhance national economic growth and achieve environmental goals.

Fourth, the industry needs to encourage and support the development of economic natural gas use within the industry, especially in vehicles and cooling. This demonstration of commitment will encourage potential customers to make the decision to use natural gas in their own facilities.

CLOSING

As the natural gas industry advances through the last decade of the 20th century, it is at a fork in the road — if it fails to deal with the issues described in this report it will likely become "dysfunctional." On the other hand, if the natural gas industry participants work cooperatively together to turn their challenges into opportunities, natural gas will realize its potential in which:

- Efficient Natural Gas Usage Contributes to the Nation's Environmental and Energy Independence Goals
- The Natural Gas Industry Meets Customer's Energy and Environmental Needs for Economic, Efficient, and Reliable Products and Services
- Federal, State, and Local Policies Support a Competitive Market for Natural Gas.

CHAPTER ONE
BACKGROUND

The "Natural Gas Industry" is a composite of many different operations performed by segments of the industry that have historically been independent, e.g., producing, gathering, transporting, distributing, and marketing. Transmission and distribution operations have generally been regulated by federal and state agencies; while producing operations are not regulated in that same context, governmental regulations of all types have had a significant impact on the industry, and the wellhead price of gas was subject to controls for much of the industry's history. Regulation has been changing recently and the natural gas industry has matured, with competition becoming more commonplace. Additionally, many industry members have become active in more than one segment of the business and new participants have emerged, e.g., aggregators. As a result of these dynamics, the industry has undergone fundamental changes and it is important to have an historical perspective in order to understand the current business environment and the future opportunities. The first section of this chapter develops that historical overview and provides a backdrop for examining the challenges faced by the industry today.

The NPC used two different approaches to respond to the Secretary's request to identify the various constraints to the increased use of natural gas. The study participants provided their views on potential barriers to increasing the use of gas in all segments of the industry. These submittals were made available to the task groups for analysis and inclusion in their final reports as appropriate. Additionally, the NPC contracted with a consultant to conduct focused interviews with representative industry and customer groups. The views expressed by the focus group participants helped to expand the understanding of the potential challenges to the increased use of natural gas. These results were also considered by the study participants and incorporated into the final recommendations. In addition to reporting the results of individual focus group sessions, an overall summary of the participant responses was developed and is included as the second section in this chapter.

The final section of this chapter outlines the methodology that was used in conducting the study. It includes a summary of the approach taken by each of the task groups and the framework that was adopted to provide analytical consistency for the study.

HISTORICAL OVERVIEW

How We Got Here

The purpose of this historical overview section is to set the stage for the discussion and recommendations that follow by providing a sense of how the industry evolved—the influences on its development that explain its structure and the historical forces that explain its behavior in response to changes in the regulatory, supply, and market environments.

The natural gas industry is considered by many to be complicated. The dynamics of

supply and demand introduce one level to the industry's complexity, while a long history of regulation adds another level. The supply is not readily apparent—reserves are not "visible" and the resource base cannot be directly measured. The capital and the time required to bring new reserves into production can result in new supplies coming on before or after they are needed. In order to service the development cost debt, there is significant incentive to produce new reserves as soon as they are available. Natural gas demand is subject to many influences, including weather, the cost of alternative fuels, perceptions about supply, and the vagaries of the business cycle. With no other influences, the supply and demand dynamics of the gas industry result in the potential for equilibrium dislocations. On top of these dynamics are layered regulations promulgated to protect gas users from abuse of market power. Over the industry's history, these regulations have at some times acted to replace market forces and, at other times, to promote market forces at one end of the pipeline and constrain them at the other end. In light of the complicated nature of the industry, knowledge of how it evolved should be helpful in understanding how it may move forward.

Natural gas currently provides about 24 percent of the country's total primary energy needs. While the United States' dependence on natural gas has declined in absolute and in relative terms since 1972, the emphasis on clean, reliable energy has grown. If natural gas is allowed to compete effectively, it should become a major component of any program to meet increased energy demand in an environmentally responsible manner, without increasing dependence on foreign sources of energy.

Although the dependence of the United States on energy imports during the OPEC cartel years and during the recent invasion of Kuwait is frequently recognized as a cause for concern and for legislation, the development of the gas supply, transmission, and distribution infrastructure has occurred with little attention to a coordinated forward-looking policy. Rather, industry participants responded to individual market opportunities that were economic or required under the regulations in effect at the time. These laws and regulations were largely promulgated in response to specific practices taking place (or feared) that were perceived as being counter to the public good. The industry that evolved under these laws and regulations owes much of its structure and characteristics to them.

At the onset of federal regulation of the gas industry, an approach was chosen that provided for extensive regulation of nearly all aspects of the industry, one that did not allow the industry to respond to market changes quickly. Current regulatory initiatives are intended to reduce the regulatory restrictions on supply and transmission in an effort to allow market forces to more effectively and quickly guide supply and demand for gas.

"Transition costs" associated with changes in regulatory policies can be substantial, particularly with the movement toward a more competitive market as was initiated by the Federal Energy Regulatory Commission's (FERC) Order 380. These costs arise mostly from reforming the contractual arrangements entered into during the previous regulatory era. The issue of transition cost responsibility is a significant one, which influences future contractual strategies and practices.

Just as changing regulations have influenced the structure of the natural gas industry, advances in technology have also left a mark. Technology has made it possible to drill in deeper water and into deeper reservoirs, into tighter sands and into coalbeds, all with a greater likelihood that the well will successfully produce natural gas or oil. Technology has not only increased the number of reservoirs from which gas can be economically produced, but it has increased the percentage of reserves that can be recovered. Technology in transmission and storage has allowed gas to efficiently serve new markets or attach new reserves to the nationwide pipeline grid. Decreases in demand due to improvement in the energy efficiency of gas-fired appliances and process equipment and to advances in conservation technology are being offset by new uses for gas in power generation, transportation, and cooling.

This section on historical perspective will review the growth of the modern gas industry, first by describing the industry today and then by exploring the history of its regulation, resource base, and demand patterns, and the development of the transmission and storage infrastructure.

Early Use of Gas

"Natural gas" is mostly methane and is generally believed to be a product of the decomposition of organic material. The gas, once formed, may migrate underground until trapped in a geological formation, from whence it is produced by drilling a well into the reservoir. The gas is then transported to market through pipeline facilities.

The U.S. gas industry was born 175 years ago when in 1816 gas manufactured from coal was used to illuminate the streets of Baltimore, Maryland. Users of gas in the 1800s either burned gas produced locally or gas manufactured locally from coal, as the technology to transport gas long distances did not yet exist. A national market, supplied by interstate pipeline transmission systems, began to evolve in the 1920s with the development of seamless welded pipe. This technology provided industrial and residential markets access to huge remote supplies of natural gas, and the location of the supply relative to the market decreased in importance. The use of manufactured gas declined in light of the availability of the less expensive "natural" gas alternative. The gas market has continued to evolve over the last 60 years, expanding to serve millions of end users while adapting to regional shifts in supply and markets.

Modern Gas Industry

The gas industry today is segmented into clearly defined functions: production, transmission, and retail distribution. This is largely due to the fact that the transmission and distribution businesses were historically considered monopolies and are each regulated by different entities. The FERC regulates the jurisdictional activities of interstate pipelines. State public service commissions regulate the activities of intrastate pipelines and local gas distribution companies. This regulation involves the approval of mechanisms and rates that allow the recovery of the costs of providing service while protecting customers from monopoly prices. In addition, the Public Utility Holding Company Act closely regulates companies that own distribution companies.

The regulatory jurisdiction of the federal government and of the states also evolved to be mutually exclusive. As a result, the functions of production, interstate transmission, and retail distribution are generally performed by different corporate entities.

With the advent of open-access transportation on interstate pipelines, additional market participants, such as independent and pipeline- or producer-affiliated gas marketing companies, have been formed in recent years.

A gas producer explores for, locates, develops, and produces gas from the field. The producer then sells the gas into the intrastate or interstate market. Intrastate sales are made by producers to intrastate pipelines, retail distribution companies, or commercial and industrial customers within the producer's state. Interstate sales were traditionally made by producers to interstate pipeline companies, but increasingly in recent years interstate sales have also been made directly to brokers, local distribution companies (LDCs), and commercial and industrial customers. Indeed, many large producers have formed large marketing departments to pursue directly the pipeline's traditional sales markets.

Historically, interstate pipeline companies carried out a merchant/aggregation function for virtually all gas flowing in interstate commerce. The pipelines purchased gas from producers at the wellhead and resold it to local distribution companies and, to a lesser extent, directly to industrial users. With recent regulatory changes, interstate pipelines are serving principally a transportation role as opposed to a sales role. There are about 32 major pipeline companies regulated by the FERC as individual companies. Recent consolidation has limited the ownership of these 32 to 18 companies.

Local distribution companies historically purchased gas from pipeline companies, which the LDCs then resold to industrial, commercial, and residential customers. Under state law, LDCs are usually granted exclusive local franchises in exchange for regulation of their retail rates and services and for the obligation to provide service to anyone desiring it.

There are nearly 1,300 LDCs in the United States. Only a few do business in more than one state, and only a few are owned by or affiliated with an interstate transmission company. About two-thirds are owned by municipal governments.

Many small marketing or brokering companies were formed in the mid-1980s when the FERC imposed open-access transportation on pipelines. These companies provide the service of matching buyers to sellers of gas and arranging transportation. Their customers are LDCs and large end users. Consolidation has occurred among the marketers, and some large brokers are emerging. As noted, producers have also set up their own marketing departments or subsidiaries to compete with the independent companies, as have pipeline companies. Independent marketing appears to have a future role in serving the many small producers that have not established a marketing expertise and in providing aggregation for buyers.

The earliest interstate pipeline systems connected one market to one supply basin. Over time, as new markets and supply sources were found, pipeline systems were expanded, extended, and at times interconnected as was necessary to provide natural gas service in a cost-effective manner. The result is a system of natural gas pipelines each built to serve specific markets with supply from specific geographic areas.

Each interstate pipeline was designed to serve a different market or purpose. Some were built primarily to supply other pipelines, others to move oil or oil products during World War II. Some pipelines are long-haul lines built to serve a primary market far from the supply area, while others are regional in nature and may be configured like a spider web network in order to serve industries and towns throughout a particular region. Whatever the genesis of a specific pipeline system, over time the systems have become interconnected. Initially this interconnectivity was primarily to provide emergency back-up for a system in the event of a supply or mechanical failure. More recently, regulatory policies have encouraged a national pipeline grid where interconnectivity can serve to facilitate the working of market forces in the supply of and demand for gas.

Throughout the history of the domestic natural gas industry, gas has served several distinct markets. As a result, gas demand must be viewed by end use in order to understand the market dynamics. Today, consumption of gas by industries represents 37 percent of total gas demand. Residential and commercial use for cooking, heating, and cooling represents 39 percent. Power generation makes up 13 percent of total gas demand.

Even within each market, differentiation is apparent. For example, industrial gas use as a feedstock for fertilizer is driven by the agriculture economy, while demand for gas to supply process heat is impacted by the national economy and, to some degree, by the price of alternative energy sources.

The sources of natural gas supply have multiplied over time. In the earliest years of the gas industry, gas was manufactured from coal. With improvements in piping and compression technology, natural gas eventually displaced coal gas. In 1930, gas supply was either local or from a few large remote reservoirs in the Southwest. Today, the number of locations of gas reservoirs has spread. Thirty-four of the lower-48 contiguous states have gas production. Seventy-one percent of all of the gas consumed has moved in interstate commerce. Imports of gas from Canada and Mexico are possible and gas can be imported in liquefied form from Algeria and other countries. Technology has made it possible to produce natural gas from coalbeds, from tight sand and shale formations, and from extremely deep water. The resource base is large and diversified.

Another characteristic of the modern gas industry is that it has suffered numerous changes in the laws and regulations that govern prices, transportation, and end use. While generally the regulations were changed to remedy specific problems, the dislocations caused by the changing regulations have left each segment of the industry scarred in some way and have slowed the assimilation of the changes.

The current transition to open access, begun with FERC Order 380 in 1984, has been particularly long and drawn out. The most recent step in this transition, the FERC Orders 636 and 636A, will not be fully implemented until the winter of 1993-94, and certain aspects of the transition could extend several years beyond that date.

History of Federal Regulation

Natural Gas Act of 1938

As noted earlier, the invention of seamless welded pipe made the long-distance transportation of gas possible and provided markets

for the large gas discoveries of the 1920s and 1930s. A couple of factors combined to influence the Congress in 1938 to pass legislation to regulate the interstate transportation and sale for resale of gas. First, there was concern that the interstate gas transmission industry was a monopoly dominated by a few large companies. A 1935 report of the Federal Trade Commission[1] suggested that natural gas prices were being distorted by this concentration of control. Second, although the markets were local and could be regulated by the states, sales for resale in interstate commerce could not be regulated by the states, creating a "regulatory gap."

In enacting the Natural Gas Act of 1938 (NGA),[2] the Congress chose not to make pipelines common carriers but rather to subject the contracts between the pipelines and their customers to regulatory review on a case-by-case basis. The NGA recognized the interstate pipelines as monopolies and set the stage for intensive regulation of every aspect of the interstate gas transmission industry. The basis for this regulation was the determination of "just and reasonable" rates for natural gas companies engaged in the sale for resale of gas in interstate commerce. "Just and reasonable" quickly came to mean that a pipeline's allowed rates would be based on a pipeline's actual costs of providing service plus some allowance for the pipeline's investors to earn a return.

In the NGA, the Congress also provided a certification process to approve new services and the construction of new facilities. In order to provide additional protection to users of gas, the Act also prohibited natural gas companies from abandoning jurisdictional services or facilities without regulatory approval even upon the expiration of a contract. This "service obligation" required pipelines to back up their sales services with long term gas supply contracts. New projects, in order to be certificated, had to be backed by firm supply arrangements as well.

All segments of the industry were generally satisfied with this arrangement for a while, and it encouraged the growth of the transmission industry. Producers had guaranteed markets for their gas. Pipelines were assured cost recovery and were insulated from competition. Distributors were assured continuity of service and were protected from monopoly pricing.

Phillips Decision

The Federal Power Commission (FPC, forerunner of the FERC) did not regulate the price of gas at the wellhead in the years immediately after the passage of the Natural Gas Act. The Supreme Court ruled, however, in its 1954 *Phillips*[3] decision that the NGA required regulation of the price of natural gas at the wellhead. The effect of the decision was to create a two-tiered market, where the wellhead price of gas produced for sale into the intrastate market was not regulated and the wellhead price of gas sold into the interstate market was regulated.

The FPC tried various schemes to regulate the maximum gas price that could be charged for gas, as the burden of regulating each individual gas contract on a cost-of-service basis was impossible. Even the alternatives to individual cost-of-service determinations turned out to be administratively overwhelming. For example, the FPC tried to determine cost-of-service rates on an area-by-area basis; these area rate proceedings took about ten years to complete. In the meanwhile, interim area rates were allowed that were based largely on historical contract prices, prices that reflected lower costs from earlier times.

Under these procedures the regulators erred on the side of low gas prices, so that by the late 1960s the price of new production sold into the price-unregulated intrastate market began to rise above the price of newly contracted interstate gas. The effect of artificially low gas prices stimulated demand, yet discouraged natural gas exploration activities for the purpose of serving the interstate market. By the early 1970s spot shortages of gas began to appear, and industrial use of gas had to be curtailed. During the harsh winter of 1976-77, the shortage had become severe in the interstate

[1] Final report of the Federal Trade Commission to the Senate of the U.S. pursuant to S.Res.83, 70th Congress 1st Session (1935).

[2] U.S.C. 717-717W (1938); note, however, that there is a common carrier requirement in the Mineral Leasing Act as it pertains to pipelines that cross public lands and that there are open and non-discriminatory access provisions in the Outer Continental Shelf Lands Act.

[3] *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954).

market, and gas was curtailed to industrial customers and power generators in the Northeast, Midwest, and Mid-Atlantic states. "Curtailment plans" to ration gas were devised, and many in the industry became convinced that the shortage was chronic and would be getting worse.

Natural Gas Policy Act of 1978

It took the extreme emergency of the winter of 1976-77 to produce a consensus in the Congress that legislative action was necessary to remedy the shortages. Even with that consensus, competing interests in the Congress produced a complex series of compromises that became the Natural Gas Policy Act of 1978 (NGPA).

The objective of the NGPA was to deregulate gas prices and allow them to increase to market rates in order to encourage gas exploration and to reduce price differentials with intrastate gas so that gas would flow to the interstate market. Complete and immediate decontrol of wellhead prices was not achievable due to consuming states' concerns about the impact of a rapid price rise on their citizens and industries. What passed was a "phased decontrol" of a complex array of different categories of gas. In addition, intrastate gas was made subject to NGPA pricing provisions. Some categories of gas were deregulated over several years. Others were price-regulated through built-in escalators on the maximum lawful price (caps) that could be charged for each category. In the latter case, these escalators were intended to bring the cost of the gas under a particular category up to a market level, competitive with other fuels. Since the estimates of the late 1970s were that oil prices would escalate at a rate greater than inflation, these escalators caused the price of such gas to eventually exceed market prices.

It should be noted that while the NGPA did not price gas directly, it set maximum lawful price caps on each of the various categories. In the sellers' market of the late 1970s, pipeline buyers could not compete for scarce interstate gas by bidding more than the maximum lawful price. Producers required, and were able to obtain, price terms tied to the highest allowable rate. Under such provisions, escalating price caps translated to escalating gas prices under contracts that included these terms. Prices of gas sold under some contracts eventually exceeded $10 per thousand cubic feet (MCF). Pipelines were able to "roll in" the cost of higher priced new gas with that of gas under older contracts so that the interstate market did not see the marginal price of new gas.

The higher prices for new gas after the passage of the NGPA did encourage the search for and development of new gas reserves. In fact, drilling activity peaked in 1981 at 3,970 rigs operating in the continental U.S., almost four times the rigs operating in 1970. The higher gas prices, however, discouraged demand. The net effect of the reserve additions arising from the new drilling and the demand erosion due to higher prices, legislated restrictions on gas use, and the national recession of 1982, was that the shortage became a surplus. In the surplus, the maximum lawful prices of gas under various pricing categories began to exceed the market price of gas. Industrial customers that could switch to fuel oil did so, further depressing gas demand.

The existence of a surplus resulted in the birth of a spot market, i.e., gas available for sale and not dedicated under a pipeline contract. In the surplus, the spot market price of gas was lower than the pipeline's average cost of gas. Pressure was put on the FERC to allow access to this low-cost gas by gas consumers, formerly served exclusively by sales from pipelines. At first, proposals to allow access to spot market gas to serve industrial users that would otherwise switch to alternative fuels were promoted by the pipelines and approved by the FERC as "special marketing programs;" these special marketing programs were later challenged as being discriminatory. The traditional sales for resale market continued to be served with the higher cost gas under contract to the pipelines.

FERC Orders 380, 436, 636

Since the pipelines had minimum bill arrangements with their resale customers that included gas costs, the FERC viewed these provisions as discouraging resale customer purchases of lower priced spot gas. To encourage purchases of lower cost supplies by pipelines' resale customers, the FERC in its 1984 Order 380 required the removal of gas costs from minimum bills. In the 1985 case, *Maryland People's Counsel v. FERC*, the D.C. Court of Appeals found that preferential access

to spot market gas was discriminatory, and the FERC was directed to respond by providing non-discriminatory access. This was accomplished by FERC Order 436, issued in October of 1985, which required that pipelines provide non-discriminatory access to transportation services.

The pipelines' minimum bills to their resale customers, invalidated in Order 380, were used to offset similar obligations pipelines had to producers under take-or-pay contracts.[4] The FERC chose not to require modification of the corresponding take-or-pay provisions in the pipelines' contracts with their suppliers when it issued Order 380.

As pipelines began to transport spot gas for resale customers under these orders, they displaced their own sales gas, and their take-or-pay liabilities to producers mushroomed. The FERC estimates that pipelines paid producers $8.2 billion to settle $44 billion in take-or-pay liabilities by 1989. The pipelines still have some take-or-pay contracts in effect.

By 1991 only 16 percent of annual interstate gas volumes were pipeline sales, even though the pipelines had been required to stand ready to supply the bulk of their customers' requirements. These sales occurred largely during the winter heating season, when the only capacity available was dedicated to firm pipeline sales services and when interruptible transportation service was not generally available.

To complete the transition to open-access transportation and to end the uncertainty the industry had been operating under since the issuance of Order 436 in 1985, the FERC issued Order 636 in 1992. This "restructuring rule" allows non-pipeline merchants to compete with the pipeline for gas sold under any firm transportation service. It also relieves the pipeline of its traditional merchant service obligation and provides opportunities for pipelines to restructure their remaining gas supply contracts in order to match the requirements of their remaining sales services.

Historically, whatever aspects of gas production, transmission, and distribution that did not fall under federal jurisdiction were regulated by the state, usually by a state public service commission or utility commission. Since federal jurisdiction over interstate transmission is almost total, state regulation is directed at distribution activities and certain aspects of production. LDC regulation may involve rate approval, LDC gas purchase oversight, and service area determinations. State regulation of production usually involves gathering, intrastate transmission, and resource management issues. All of the states do not approach their gas regulation in the same way, although they must all react with changing federal regulations.

Development of Markets

Gas consumption grew from a little under 2 trillion cubic feet (TCF) in 1930 to 22 TCF in 1972. Historical gas demand growth, however, should not be viewed in total. Natural gas is a versatile resource that serves many uses: as an industrial fuel; in residential cooking, heating, and cooling; for power generation; and as a chemical feedstock. Demand in each of these submarkets has been affected by a myriad of factors.

In the national energy mix, the share of gas is currently 24 percent of primary energy demand. The price, availability, and clean-burning qualities of gas relative to other energy alternatives influence the share of total energy demand supplied by natural gas. While price is a primary consideration in the choice of fuel, instantaneous price is not the overriding factor in fuel selection for all gas consumers. Energy-using equipment is capital-intensive and economic "sunk" costs can dampen fuel switching, particularly in residential and commercial markets.

Market Development by Segment

Residential and Commercial Sector

Historically, residential demand for gas in the short term has been driven by weather and in the longer term by the cost of alternative fuels and by the technologies and practices that enhance conservation. Regional or

[4] Take-or-pay contracts required pipelines to purchase a minimum percentage of a well's deliverability and to pay for the gas regardless of whether or not they took the gas (subject to certain opportunities to take the gas later). Pipelines entered contracts with these provisions during the shortages when they could not compete with other buyers on price because of the maximum lawful price caps.

local availability of natural gas supplies has also been a factor in the level of demand, as many areas of the United States did not have the transmission or distribution facilities to provide residential service 60 years ago.

In 1930, the residential sector consumed one-third of a TCF of natural gas, which represented 16 percent of all gas consumed. As gas became more available nationally, it rapidly gained share as a residential cooking and heating fuel. By the 1960s, residential consumption peaked at 26 percent of the natural gas market, and gas was found in 43 percent of the homes in the United States. During this period of growth, residential gas consumption not only grew with the country, but grew at the expense of other fuels such as coal and fuel oil, due to its price, cleanliness, and ease of use.

During the late 1970s, gas demand declined, partly due to conservation efforts undertaken as a result of the energy crisis and partly due to price competition from electricity for space heating and air conditioning. More recently, the gas share of new residential construction has been rising and is at its highest percentage since 1988.

The commercial sector of gas demand has always been the smallest sector. It has only grown from 5 percent of gas consumption in 1930 to 14 percent in 1990.

Electric Utility Sector

The pattern of gas consumption by electric utilities generally mirrored industrial consumption, but at a lower volumetric level. This reflects the price-sensitive nature of the electric utility users because they, like many industrial users, have substantial fuel switching capability. In addition, because of the relatively high fixed cost of certain types of electric generation plants such as nuclear plants, utilities tend to use these plants for baseload generation and to rely on gas for peaking or for stand-by services.

The use of natural gas in power generation grew slowly, reaching 1 TCF in 1954. From 1954 until 1971, consumption by this sector grew rapidly, peaking at 4 TCF in 1971. During the 1970s, gas demand by electric utilities declined by 25 percent due to the relatively cheap cost of coal and appearance of gas curtailments. It was during the late 1970s that the electric utilities began to view gas as a diminishing resource. This perception was strengthened by the passage of the Powerplant and Industrial Fuel Use Act in 1978. The advent of the gas deliverability surplus and open-access transportation has not caused gas consumption by electric utilities to rise significantly. In 1990, gas use for power generation approached 3 TCF.

Industrial Sector

The general level of economic activity affects demand for gas through its influence on industrial energy requirements. Industrial demand for gas is very sensitive to the level of activity in the economy and to the price levels of alternative fuels, such as coal and fuel oil. Since industrial demand is such a large fraction of the total gas market, it has historically been key to the health of the industry.

In 1930, industrial consumption of gas represented 39 percent of all natural gas consumed. The industrial activity associated with the war effort in the 1940s caused a rapid increase in the demand for gas and put a strain on the gas transportation infrastructure and on supply availability. After the war, the demand continued to grow, peaking at nearly 9 TCF in 1973.

The curtailment of the 1970s and the passage of the Powerplant and Industrial Fuel Use Act convinced many industrial gas customers that gas was a diminishing resource and that it would not serve as a reliable fuel. These industries installed the capability to switch to alternative fuels such as coal or oil.

Industrial gas demand dropped 18 percent between 1981 and 1982, due to the national recession and relatively low oil prices. This decline in industrial consumption in the early 1980s was a significant factor in the formation of the gas deliverability surplus that developed.

Regulatory rate and transportation policies along with low gas prices have allowed the gas industry to recoup some of the market share lost in 1982. The industrial consumption of 7 TCF in 1990 is higher than at any time since 1981.

History of Supply

Overview of Resource Base

Important to understanding the dynamics of the gas industry is knowledge of the extent of available reserves and of the interplay between gas price and exploration and development activity. One factor affecting supply and price is the ability of new technology to make previously non-economic reserves economic and to improve the success rate of exploratory wells. Technology that has resulted in an increase in producible reserves includes fracturing techniques for tight formations, coalbed methane recovery technology, ultra-deep-water drilling technology, and horizontal drilling, among others.

There are several aspects to quantifying gas "supply:"

- Well deliverability
- Proved reserves
- Total resources.

Deliverability, the capacity to produce gas, is a measure of the rate at which gas can be produced, not a measure of the adequacy of the inventory of gas. Deliverability can be increased through the drilling of wells in existing, developed fields or in previously undeveloped reservoirs. In general, such investment in new wells is undertaken when the market can absorb the gas that will flow from the new wells at prices that will allow the producer to earn a return on its investment. Proved reserves, on the other hand, are a measure of inventory, a fraction of the total resource base that has been measured and is known to be economically recoverable.

Domestic Resources

In the latter part of the 1960s, additions to the proved reserve inventory fell below annual production volumes as producing companies reacted to the increasing economic pinch of low (regulated) gas prices and rising costs. Producers cut back on exploration and development of new gas resources as a means of reducing their inventory (proved reserves) of gas to a more economically efficient level. The shortages of the late 1970s were not caused by an actual shortage of resources but were rather a reaction to market conditions that made development of further resources uneconomic. When prices were raised enough to make drilling for higher cost reserves economic, a flurry of drilling activity resulted in reserve replacement that exceeded production.

Imports

The United States has been largely self-sufficient in its consumption of natural gas. It has only been importing and exporting natural gas to any measurable degree since 1955, and importation of 9 percent of its requirements in 1991 was the highest level of gas imports ever. Although the United States has historically exported natural gas to Japan, Mexico, and Canada, it has been a net importer of natural gas since 1958. The growth in net imports has not been steady, however, as government regulation (in this country and others) has at times been in conflict with market forces and chilled the international gas trade.

Canada has by far been the largest supplier of gas to the United States. This is primarily due to the large gas reserves in Canada and their relative proximity to northern U.S. markets. Net imports from Canada grew from the late 1950s until 1973, when regulatory policies in Canada resulted in Canadian gas being priced higher than U.S. domestic gas. In 1983 Canadian regulatory reforms were initiated that, along with the passage of the 1989 Free Trade Agreement with Canada, began to make Canadian supplies increasingly competitive in the U.S. market. Canadian imports have recently surpassed their 1973 peak, reaching 1.7 TCF or 9 percent of total U.S. consumption in 1991.

Mexico has not been as significant an exporter of natural gas to the United States as has been Canada. Although Mexico has large proved reserves relative to its domestic consumption, lack of pipeline infrastructure and capital are considered primary reasons why Mexico has not played a larger role in supplying U.S. gas demand. Between 1980 and 1984 Mexico was exporting an average of 86 billion cubic feet (BCF) per year to the United States. These exports were suspended at the end of 1984 due to U.S. and Canadian price declines. In recent years, the United States has been an exporter of gas to Mexico as Mexico concentrates on displacing higher polluting fuels with gas in power generation and industrial markets.

During the 1970s, a new supply source became available to satisfy U.S. gas demand: liquefied natural gas (LNG). As the gas shortage became evident in the 1970s, several gas transmission companies built terminals to receive gas in liquid form at cryogenic temperatures. Gas was liquefied through refrigeration in Algeria and shipped to one of four terminals on the East and Gulf coasts.

LNG imports peaked at 253 BCF per year in 1979. Although LNG imports were viewed at the time as an effective way to avoid curtailments caused by supply shortages, several factors combined to halt gas imports for a time. The Natural Gas Policy Act limited pipelines' abilities to roll-in the higher cost of LNG supplies. The LNG price was tied to higher-priced fuels, and the contracts included 100 percent take provisions. These provisions along with the recession of the early 1980s and the emergence of the spot market resulted in LNG being uncompetitive with domestic supplies. Imports had ceased at each of the terminals by 1986.

Imports resumed to one of the four terminals in 1988 and to another in 1989. Pricing of LNG under these contracts has been modified to be more market-responsive.

Nonconventional Gas Supplies

Traditionally, natural gas was either produced in association with oil or from reservoirs where the geology made it readily recoverable. With advances in production techniques, gas that was not considered to be economically producible many years ago is available to meet demand today. Due to the different nature of these resources, and knowledge about their extent, these resources are considered to be "nonconventional." Two examples of natural gas from nonconventional sources, which are becoming more significant contributors to the domestic supply mix, are "tight" gas and "coalbed methane" or "coal seam gas."

Tight gas is that produced from formations in which the natural permeability is very low, making it difficult for the gas to flow through the formation to the well. The advent of hydraulic fracturing techniques in the 1940s and subsequent advances in fracturing have made it possible for tight gas to be economically produced. The NGPA recognized the potential of tight gas to contribute to U.S. supply and provided incentive prices for this production. In addition, a nonconventional fuels tax credit was provided in 1980 to assist in the commercial development of tight gas. By 1981 production from tight gas wells reached 1.2 TCF. With the decline of gas prices in the early 1980s and with much of the tight gas becoming ineligible for the tax credit after its deregulation, tight gas became less attractive and its production decreased. With amendment of the tight sands eligibility provisions for the tax credit in 1990, tight gas development once again began to accelerate, and production is expected to reach nearly 2 TCF in 1992.

Methane is present in coal and is a chief reason for coal mine fires. Traditionally coal mines are well ventilated in order to allow the methane trapped in the coal to be vented to the atmosphere without the danger of a combustible mixture of air and methane. Experience, improved techniques for producing coalbed methane from unmined coal seams, and the stimulus of a federal production tax credit have resulted in a significant addition to the U.S. gas resource base. Production of coalbed methane gas has increased from 40 BCF in 1988 to about 350 BCF in 1991.

Changes in Contracting Practices

Important to understanding the impact of regulatory transitions on the dynamics and the financial health of the natural gas industry is an understanding of the contracting practices employed prior to these transitions.

During the growth years of the transmission industry, the contracts under which producers sold gas to pipelines were necessarily long term (e.g., for 20 years or for the life of the gas reserves). Long-term contracts gave the lenders of capital assurance that sufficient reserves were connected to the pipeline to allow it to amortize the capital cost of construction and gave the regulators and the pipelines' customers assurance that the facilities included in the rate base would be useful over their life.

Historically, pipelines were gas merchants and were not required to provide transportation. Thus a long-term contract with a pipeline also gave the producer and its lenders some certainty that it would be able to sell its gas.

When the regulators began controlling the wellhead price of gas below its market price in

the 1970s, producers slowed exploratory and development drilling, and shortages developed in the interstate market. The pipelines were in critical need of gas and, since a pipeline could not compete with other pipelines for a package of gas on the basis of price (given regulation of maximum lawful prices), it bid on the basis of non-price terms. Such non-price terms typically would include "take" provisions (such as requiring a pipeline to take a specified percentage of deliverability). Terms may also have included pricing terms, such as requirements that a pipeline pay the producer an amount equal to the highest price it was or would be paying other producers of gas in a particular area.

When the deliverability surplus became apparent during the recession in the early 1980s and when new supply sources came on line after institution of the higher post-NGPA prices, pipelines were not able to perform under take-or-pay contracts signed during the shortages. The inability of a pipeline to take gas that it was obligated to take was made worse by FERC actions that gave the pipelines' customers the opportunity to buy cheaper spot gas from others and use the pipeline for transportation of this third-party gas.

The transition to open access, which began in 1985 with Order 380, has not yet been completed. The pipelines, encumbered with contracts entered into during a period of regulatory induced shortage, have not been able to completely reform or terminate these contracts.

In the open-access world, end users can enter long-term contracts directly with producers, but seem reluctant to do so, apparently for two reasons. First, for the last several years market participants have known that some regulatory changes were necessary to bring stability back to the industry. There has been a reluctance to enter long-term arrangements when significant regulatory change is imminent. Second, with the low gas prices of the deliverability surplus, producers have wanted to wait until prices firmed, and end users have been content to buy historically inexpensive spot gas on a 30-day basis, apparently finding security in the fact that pipelines still have their obligation to serve their traditional customers with merchant gas. Exacerbating these differing views has been the disagreement as to whether long-term contracts should command price premiums or discounts.

FERC Orders 636 and 636A are intended to complete the transition to open access and to allow market forces to work on gas supply and demand. Once this order is final, it is expected that some of the stability historically provided by long-term contracting will return. Orders 636 and 636A give parties an opportunity to negotiate their own contractual terms and relieve the pipelines from their obligation to stand ready to supply historical customers if their own supply arrangements fall through.

Growth in Capacity and Interconnection of Transmission and Storage Facilities

The modern interstate pipeline systems began in the 1920s, with the development of seamless welded pipe that allowed for the transmission of gas over long distances. With the discovery of large gas reserves remote from developing markets, the growth in transmission pipe was strong. In the 1930s, 50,000 miles of transmission line were in operation. Today there are over 280,000 miles of pipeline.

In the 19th century, the domestic gas industry was dominated by manufactured gas, typically produced locally and used to illuminate urban areas. By the beginning of this century, Pennsylvania and West Virginia were the leading gas producing states, and small interstate natural gas markets had come into existence 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 seamless 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 regional sections disconnected from each other:

- The Mid-Atlantic/Appalachian area, including Ohio

- An area essentially connecting the Southwest Central and Central regions with the Gulf Coast states, excluding Florida
- Small segments spread throughout the North Central states
- 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 and supply areas have required continuing expansion of pipeline facilities. Since the 1972 peak, the industry has added over 20,000 miles of pipeline. Complementing the growth of transmission lines was the expansion of storage systems. As gas markets become 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. Underground storage was first attempted in the 1880s in the depleted oil and gas reservoirs of the Appalachian basin. The first successful underground storage facility in the United States was in Kentucky in 1916.

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

1930s Through World War II

- The initial connections between Southwest Central suppliers and Midwest markets were made in 1931 (Natural Gas Pipeline Company of America, Panhandle Eastern Pipeline Company, and Northern Gas and Pipeline Company). By 1944, Tennessee Gas Pipeline Company linked the Southwest Central region with Appalachia through a 1,265-mile pipeline.
- Storage capacity increased at an annual average rate of 19 percent from 1930 to reach 251 BCF by 1945. 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: Rocky Mountain producing regions to the 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, while some volumes also came from Mexico and from Algeria as LNG.
- 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 was developed, with extensive interconnections between systems.
- Transmission line mileage increased at one-half percent annually, reaching 280,000 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 the Cove Point, Maryland, and Elba Island, Georgia, facilities in 1978. A fourth facility was opened in Lake Charles, Louisiana, in 1982.

The Status Quo

Natural gas already is a significant contributor to the nation's energy supply, as one would expect given its cost, environmental qualities, and the existing production, transmission, and distribution infrastructure. The number of potential new uses of gas, for example in transportation and power generation, is growing, and it appears that the recognition of gas' environmental qualities is now almost universal.

The industry is currently undergoing a regulatory transition that moves towards lighter-handed regulation and greater reliance on market forces. Although in this environment natural gas has the potential to make a greater contribution, increased consumption may be hindered by certain physical constraints and also by energy users' expectations and perceptions. Whether or not gas use can grow to meet its potential will depend on how the industry addresses both the perception and the reality of existing constraints. These barriers, many of which are vestiges of the industry's history, are addressed in this study, along with strategies to mitigate them.

CHALLENGES TO INCREASED GAS USE

The natural gas industry faces several challenges as it moves toward the goals, outlined in this study. These challenges arise from the experiences of companies from customers' experience with the industry in the past, and from concern about how the industry is changing. Ignoring these challenges would be harmful to the industry, the national economy, and environmental policy.

This section documents and explores the most important challenges—but does not attempt to answer them. These challenges, and the questions that define them, arise directly from the observations and experience of study participants and from the perceptions of customers as solicited through the focus group process. To be clear about who needs to do what, these challenges are separately considered in two groups: those facing the industry and those facing policy makers and regulators.

The history of the natural gas industry in the United States has been dominated by extraordinarily intrusive governmental regulation. In many clear cases, that regulation can be shown to have distorted the operation of otherwise responsive, competitive markets. Consequently, while there might be much to explain about this history, it may not explain much about the future.

Industry Challenges

Study participants spent a significant amount of time focused on proposed changes in the way regulators should deal with the industry, but agreed that the most important challenges are the ones that the industry must meet itself. Consequently, the NPC considered challenges to the companies of the natural gas industry first.

In general, challenges to the companies that make up the natural gas industry fall into three categories:

- Reliability Concerns
- Behavioral Issues
- Lack of Customer Orientation.

Each of these areas deserves some definition and consideration.

Reliability Concerns

Natural gas customers are concerned about the reliability of natural gas in meeting their energy needs. These reliability concerns arise from real experiences as well as perceptions of customers; consequently the industry has the burden to prove it is reliable. Before attempting to address this issue, the industry needs to pose the basic questions that naturally arise from its customers.

"Will natural gas be available to customers in the future?"

The history of the U.S. natural gas industry includes notable cases where natural gas did not prove to be reliable as judged by customer needs. In particular, the curtailments of the

late 1970s remain fresh in the memory of many energy consumers. Additionally, rare natural conditions such as the extended extraordinarily cold period in December 1989 or the effects of Hurricane Andrew in 1992 serve to test parts of the natural gas delivery system. Each case was followed by intensive study, speculation, and, occasionally, policy change.

Much of the concern about the industry's ability to deliver natural gas and related energy services in the future arises from these experiences. The industry has the obligation to prove to its customers that supply can be available in the future, that delivery systems can be in place, and that services can be developed that meet their needs. As, importantly, customers are concerned with whether all this can be accomplished at a price that is competitive with other energy sources.

"Can the natural gas industry reduce uncertainty about reliability?"

Natural gas consumers' experience with reliability depends heavily on the type of customer served. In the past, reliability of natural gas service has been effective to residential and small commercial customers. With curtailments and confusion during regulatory change, industrial and power generation customers have had a less impressive experience with natural gas reliability.

The industrial and power generation demand sectors not only have the greatest reliability concerns, but represent the most promise for growth. As commercial interactions within the natural gas industry shift from a regulated to a contractual base, some of these concerns should fade. However, the development of a set of reliable services designed to meet customer needs, and the marketing of those services, remains a serious challenge to the industry.

Ultimately, the best argument for reliability is a healthy, competitive, and service-oriented natural gas industry. As such an industry evolves, concerns that arise from its past should begin to fade.

Behavioral Issues

Sometimes, the behavior of natural gas companies undermines efforts to develop the industry they want. Perceptions of inefficiency, fragmentation, and overdependence on government regulation exist among customers. Individual companies are the only actors who can overcome those perceptions.

"Why isn't the natural gas industry more efficient?"

Many customers believe that the regulated sectors of the natural gas industry have little or no incentive to become more efficient. This perception arises from the belief that with regulation, economic incentives are masked and that regulatory game playing is rewarded. As regulation rolls back from potentially competitive markets within the industry, and as innovative regulatory approaches develop, these concerns can be addressed more effectively.

"Why are natural gas companies always fighting with one another?"

Competition in the context of an open, competitive market creates very good results for customers. Unnecessary fighting, without regard to customer reactions in the context of regulatory hearings, sends dangerous signals to customers. Where that type of fighting gives the impression that different types of natural gas companies cannot work together, the customer will be convinced that reliable energy services cannot be developed. The consequences of *how* the industry fights regulatory battles, when they are necessary, should be kept in mind.

"Will natural gas companies be able to manage with less regulation?"

In the past, regulators have provided the equivalent of a decision-making process regarding the natural gas industry's future. In the emerging, more competitive market, individual businesses must develop their own vision of the future. If that vision is based on customer needs and followed by effective action, that company can flourish. If not, the company will fail, in spite of any regulatory efforts.

The natural gas industry could try to blame all the challenges it faces on its regulated history, but ultimately it is the behavior of the companies making up the industry that has the greatest effect. As regulatory constraints

disappear and competition emerges, there is no reason to expect that companies will not develop the abilities to compete effectively. The most important of these is greater consumer orientation.

Lack of Customer Orientation

Somewhere in its history, the natural gas industry lost touch with many of its customers. Perhaps the problem was caused by the restricted ability to develop an array of effective services in a regulated environment. Perhaps market growth in the past was driven more by macroeconomic forces than by competition, allowing companies to ignore some customer needs with impunity. For whatever reason, the greatest challenge for the natural gas industry is to get reacquainted with its customers.

"Why isn't the marketing of natural gas more effective?"

In the past, natural gas marketing consisted of passing a commodity down a chain in the general direction of the end user. Producers sold to pipelines, pipelines to distributors, and distributors to end users. All these commercial relationships had extensive regulatory limitations. Natural gas "marketers" were order takers.

Today, the marketing possibilities of natural gas and a whole array of related services are virtually unlimited. Many natural gas companies playing integrated energy service roles are bundling services along the line from producer to end user. As these roles develop, the ability to create, advertise, and deliver innovative services must improve significantly. Companies that can add value are already developing that marketing capability, which is critical to a successful natural gas industry future.

"Can the natural gas industry develop services that meet my needs?"

With the unbundling of transmission (and distribution) services, a variety of energy service companies are beginning to re-bundle services designed to meet specific customer needs. Full development of possible services requires that all segments of the industry explore new and more effective ways of using talents, facilities, and experience. This change of orientation in all segments of the industry will not be easy, but could be profitable for those who become most effective. That profitability constitutes the incentive.

"Will the natural gas industry support the development of technology?"

The clear pattern of the past is that the unregulated sectors of the natural gas industry (i.e., producers) have made extensive use of technology development to improve their profitability. An equally clear pattern is that regulated companies that did not have a chance to profit from technology investment (e.g., pipelines and distributors) have not invested. Developing some way to bridge this historical gap is a major challenge to the emerging industry.

Government Challenges

While government policy and regulation cannot change the way the industry operates, it can constrain the ability of industry to react to customer needs. Government and regulatory policy makers should minimize intrusion into markets where competition can exist, and weigh the additional costs in all markets.

Given that there is a continuing role for governmental action in the natural gas market, there are challenges for that role in the emerging industry. In general, natural gas industry challenges for government fall into three categories:

- Effective Economic Policies and Regulation
- Appropriate Environmental Policies and Regulation
- Patience with Industry Transition.

Each of these areas deserves some definition and consideration.

Effective Economic Policies and Regulation

During a period of industry transition, particularly transition aided and encouraged by regulatory policy, the most important function of regulators is to be clear about the goals of regulatory change. Uncertainty that arises from regulatory change can limit the efficient

and effective development of markets. That uncertainty is a natural by-product of needed change, but can be exacerbated by a lack of clarity.

One dimension of this challenge is finding a consistent view of clearly expressed public interest goals. Another is to develop greater consistency between state and federal regulation. Still another is the development of procedural approaches that encourage communication and responsible behavior by industry participants.

Appropriate Environmental Policies and Regulation

Natural gas can play an increasingly effective role in the achievement of national environmental policy goals. However, clean-air benefits of natural gas are not explicitly considered in environmental regulation of production or consumption in some areas. The challenge to government policy is to appreciate the net environmental benefits of natural gas and express responsible trade-offs in policy.

Patience with Industry Transition

Finally, as the natural gas industry develops the ability to operate more effectively and with greater consumer orientation, regulators and policy makers will have to exhibit the patience to allow that change to happen. The emerging industry will not look like the historical industry, and lessons learned from the past will become increasingly dangerous to apply in the future.

The challenges described above are serious, but manageable. The more competitive, consumer-oriented companies of the future industry will be naturally more attuned to customer concerns. Regulators will be less concerned because of increased consumer satisfaction. This study is designed to map out some strategies for achieving those goals.

STUDY APPROACH AND METHODOLOGY

The Secretary in his letter to the NPC requested:

> **a comprehensive analysis of the potential for natural gas to make a larger contribution, . . . to our Nation's energy supply . . . [and] . . . to consider carefully the . . . potential barriers that could impede the deliverability of gas to the most economic, efficient and environmentally sound end-uses.**

In responding to this request, the NPC considered it essential not only to examine opportunities for growth of natural gas use and potential constraints to that growth, but also to develop options and recommendations for overcoming those constraints. The principle that was adopted for determining which recommendations were appropriate to include in this report was based on a policy of neutrality without favoring one energy source over another, preferring instead to let economic efficiency and the marketplace determine the fuel choice. This resulted in the following guidelines:

- Recommendations should be included for actions by industry or government that would result in removal of barriers to increased gas use, when such use is justified on an economic, efficient, or environmentally sound basis
- It is appropriate that recommendations address government policies/regulations that favor other energy choices or implicitly penalize natural gas
- It is appropriate to identify options that could result in increased gas consumption under conditions that might require favored treatment of gas, without recommending that these actions be adopted.

As outlined in the introductory paragraphs of this chapter, potential constraints to the increased use of natural gas were solicited from numerous sources and are included in the analyses and recommendations contained in this and other volumes of the report. The breadth of the study requested by the Secretary specified the charge provided to each of the task groups. This was supplemented by each task group developing, in concert with the Coordinating Subcommittee, a specific statement of mission and objectives. Additionally, to provide analytical consistency across the entire study,

the NPC specified two scenarios for analyzing the identified growth opportunities.

Early in the study it was determined that sufficient numerical models existed within the consulting community that could be used for the study and that it was not necessary to develop new modeling capabilities. In some instances, however, certain model modifications and extensions were required and the NPC contracted for these model changes by the consultants. In all cases, the NPC study participants specified the key input assumptions that drove the models.

The time scale decided on for the study extends through 2010. This time horizon was considered minimal in order to account for investment decisions over the next 10 to 20 years, which depend on projections of long-term supply and demand. In addition, the supply of natural gas was examined for its ability to satisfy domestic gas demands out to 2030 at various assumed price levels.

Scope of Task Group Activities

Chapters Three through Twelve of this volume contain a summary of the results and recommendations arrived at by the Coordinating Subcommittee and task groups. This section overviews the approach taken by the four task groups and how the activities were interrelated.

- ***Source and Supply Task Group:*** The major focus of this group was analyzing the natural gas resources potentially available for domestic consumption in the United States, estimating the cost of accessing this gas, and determining potential barriers to its availability. They gave consideration to import/export trade with Canada and Mexico and to imports of LNG. They studied the resource base in the United States and Canada in detail and made estimates of the recoverable volumes of gas from both conventional and nonconventional reservoirs, including an estimate of the undiscovered resource potential. A consultant collected proprietary cost data covering recent activities in tight sands areas as a supplement to more readily available information in the other producing areas. A significant determinant of future costs in all areas will be the rate of advancement of technology, e.g., drilling efficiencies, exploration success rates, and recovery efficiencies. The task group conducted an analysis of technology improvements in the industry over the past 20 years. This formed the basis for estimating future advances. They examined the various environmental initiatives likely to affect the producing industry in the future with an assessment of costs and implications on supply availability. The integration of all of these factors was accomplished through use of the Hydrocarbon Supply Model described later in this chapter.
- ***Demand and Distribution Task Group:*** This group examined the opportunities for increasing the potential gas market for all sectors that consume natural gas, i.e., residential, commercial, industrial, transportation, and electric generation. They also considered the impact of new technologies available to the industry. These opportunities vary across the country, and the task group undertook 10 regional studies to document those differences. The substantial obstacles faced by the natural gas industry in capturing these potential markets were identified and recommendations were developed to help overcome these barriers. Particular attention was focused on the delivered price of gas in comparison to alternatives available to the customer, reliability of service, understanding and addressing customer needs, activities directed at reducing overall energy demand levels, and the current and evolving regulatory and environmental requirements.
- ***Transmission and Storage Task Group:*** The transmission and storage system provides the critical link between the shifting customer needs and the slowly changing location of potential supplies. This group made a comprehensive assessment of the current system and its ability to supply both annual and peak requirements. The need for new facilities to satisfy future requirements was addressed as well as the cost of those facilities. The group examined the impact of factors such as the regulatory process, rate-making procedures, reliability, quality and standardization of service, customer orientation, technology,

and environmental compliance. Specific actions were identified for improving the ability of the industry to provide more economic, efficient, and reliable natural gas service responsive to the customer needs.

- ***Regulatory and Policy Issues Task Group:*** The major effort of this group was devoted to developing a vision for regulation in the industry and discussing, with recommendations, how that vision should be implemented at the federal and state level. Implementation requires action by both industry and government and those activities were addressed. Interactions with other task groups provided consistency in considerations of environmental regulation, tax policy, and government funding of research and development within the industry. The scope of this group's activities was not confined to regulatory and policy issues only. It was also responsible for coordinating and interpreting the focus group interviews with representative industry and customer groups, which were discussed earlier in this chapter. Results of those interviews were distributed to all of the task groups for their consideration.

Modeling Approach Used in the Study

Many of the potential obstacles to the increased use of natural gas are difficult to quantify and must be described in qualitative terms, including the potential benefit or impact if the obstacle could be removed. Where possible, however, the NPC considered it beneficial to quantify the effects of those variables that could be characterized analytically. A specific methodology was adopted in order to provide consistency in the evaluations. This involved the selection of descriptive scenarios of future events as well as numerical models to quantify potential outcomes.

Recognizing the inherent uncertainty involved in projecting future events and their impacts, the NPC elected to conduct the evaluations under two different scenarios. These scenarios were selected to be sufficiently different from one another so as to provide alternative but realistic views of the future. Neither one is characterized as a "most likely" projection of the future nor as extreme or bounding cases. The two scenarios are described in Chapter Two.

The ability to satisfy future energy requirements with natural gas will be dependent on many different factors, including the (changing) energy needs of the market, the cost of producing and delivering the gas to the ultimate consumer, the price and availability of alternative energy sources, the cost of complying with regulatory and environmental requirements, and the restrictions that might be imposed by those requirements, etc. Perceptions and uncertainties in all of these areas also affect decisions about use of natural gas; these, of course, are difficult to model and their effects can only be estimated. Several different types of models were used to quantify projections under the two alternative scenarios. These included "macro" projections of world oil demand and price and of domestic energy and economic growth, along with a set of models that balanced natural gas supply, demand, and transportation within the more macro framework. A schematic of this approach is depicted in Figure 1-1. Although there are certain interdependencies among the various models, they generally are not linked interactively, the exception to this being the gas supply/demand models depicted in the lower portion of the figure.

In reviewing the characteristics of natural gas supply and demand models available from various sources, it was concluded that most of the models had similar descriptions of the demand sectors and that the major differences were in the detailed description of the natural gas resource base and the transmission system. On that basis, the NPC decided to contract with Energy and Environmental Analysis, Inc. (EEA) to conduct the supply/demand analysis. The models available from EEA and their capabilities are described in Volume VI, Chapter One, and will only be discussed briefly here. Additionally, Volumes II through IV contain specific descriptions of the relevant models and how they were used in the analyses. Figure 1-2 depicts EEA's Energy Overview Model, which simulates the natural gas supply/demand balance through use of three sets of model components—the Hydrocarbon Supply Model, the Pipeline Model, and the End-Use Sector Models.

The Hydrocarbon Supply Model was originally developed under contract from the

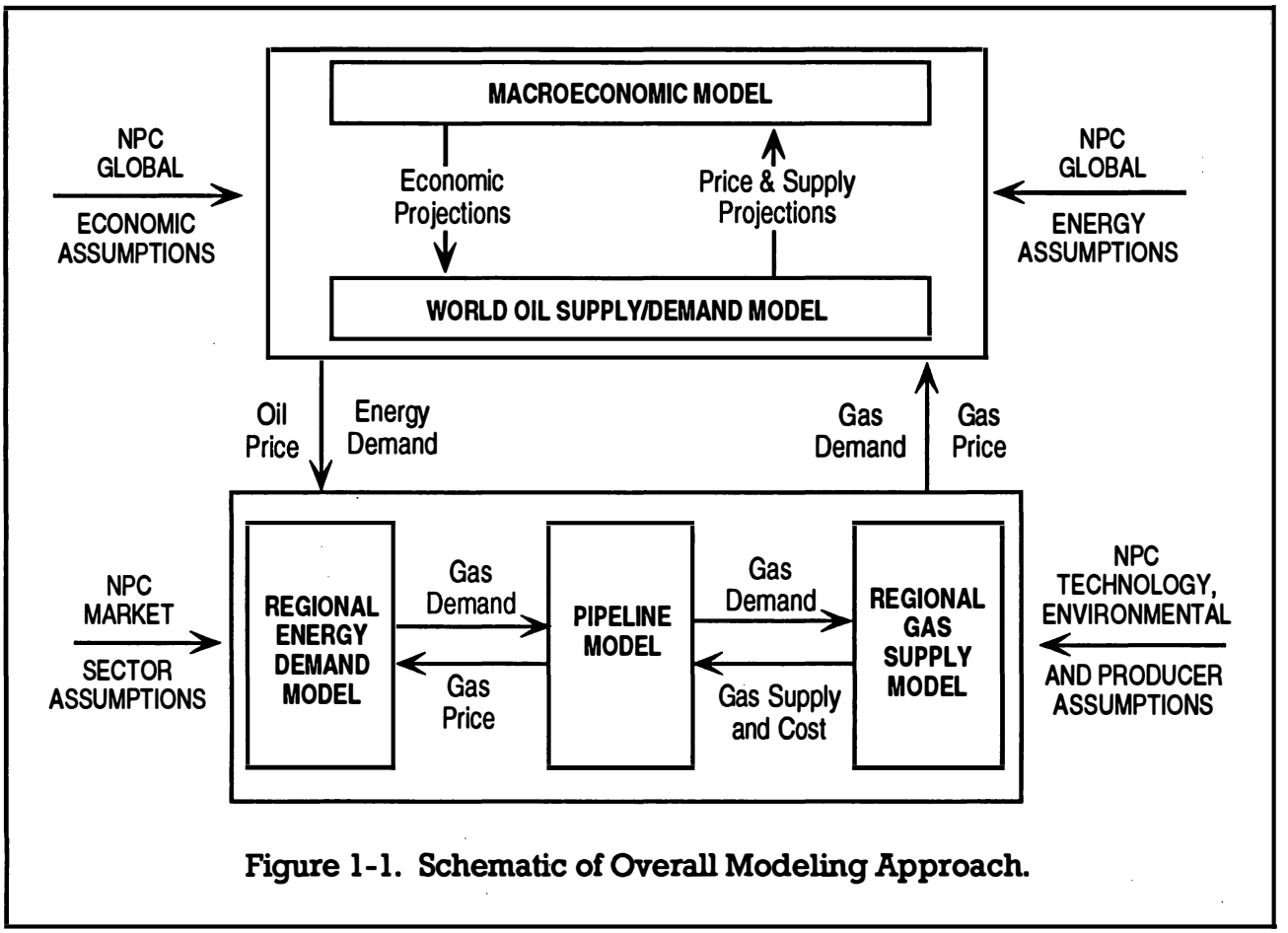


Figure 1-1. Schematic of Overall Modeling Approach.

Gas Research Institute and describes not only the potentially recoverable resource base but also the impact of technological advancements and exploratory and development drilling activity. This activity is dependent on producer investment decisions, which are in turn influenced by price expectations, desired rates of return, reinvestment ratio limitations, etc. The resource base contained within the model covers both the United States and Canada and is divided into multiple regions (Figures 1-3 and 1-4), each with their own geological and operating characteristics. Each of the regions is further subdivided by depth and type of gas resource, e.g., conventional, tight, coal seam, and shale. Uncertainties in resource base, behavioral, and technology assumptions can be easily evaluated.

The EEA Pipeline Model simulates flow from producing regions of the United States and Canada to the various consuming regions (the 10 federal regions for the United States plus Alaska, and 7 regions in Canada) (Figures 1-5 and 1-6). It uses composite pipeline groups along major corridors linked to composite distribution companies in each of the consuming regions. Transmission and distribution costs are included in the model as well as discounting flexibility in the competitive markets. Core and non-core markets are treated independently and the model calculates both firm and interruptible transport rates. The model can handle a variety of different contract terms and various regulatory environments; however, FERC Orders 636 and 636A are not fully modeled as the conditions were still being debated at the time of this study.

The End-Use Sector Models cover the major markets that consume natural gas (Figure 1-7), with the exception of the transportation sector, which must be analyzed exogenously. Both econometric and process engineering approaches are used in the demand models. The Residential and Commercial Sector Models are largely an econometric forecasting structure that was derived from and calibrated against more complex process engineering models of energy use and technology

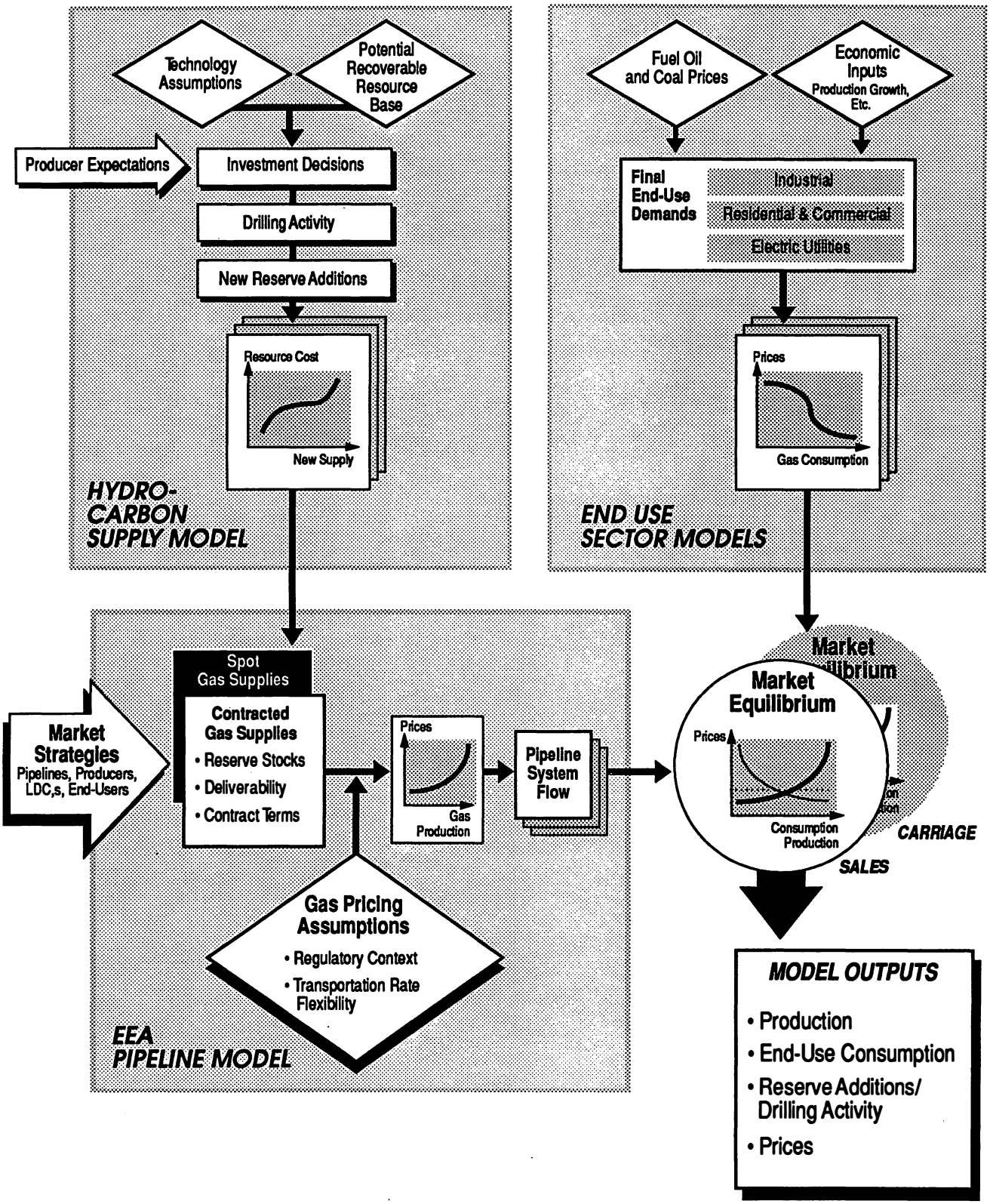


Figure 1-2. Energy Overview Model from EEA.

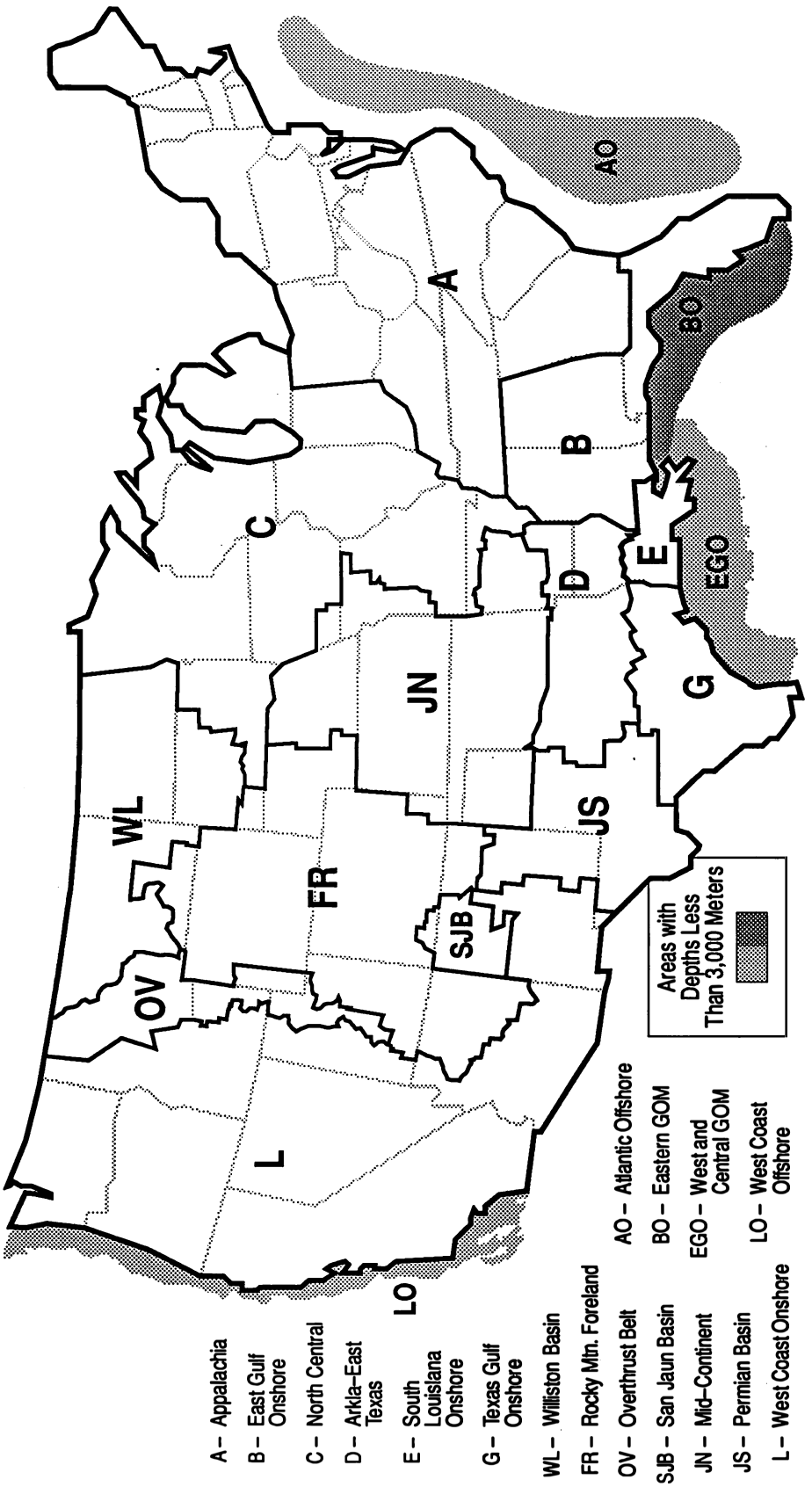


Figure 1-3. Lower-48 Hydrocarbon Supply Regions—EEA Model.

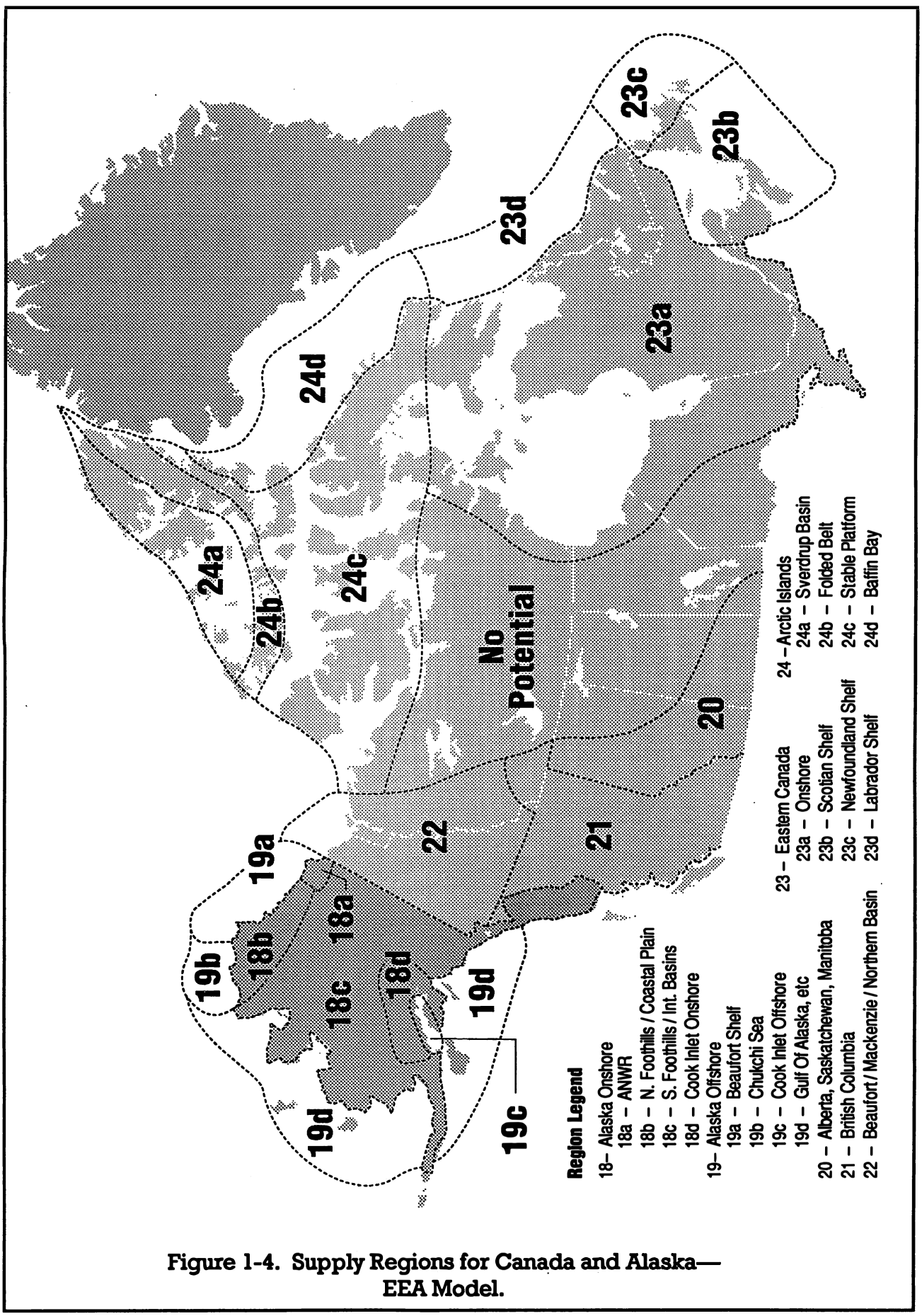


Figure 1-4. Supply Regions for Canada and Alaska—EEA Model.

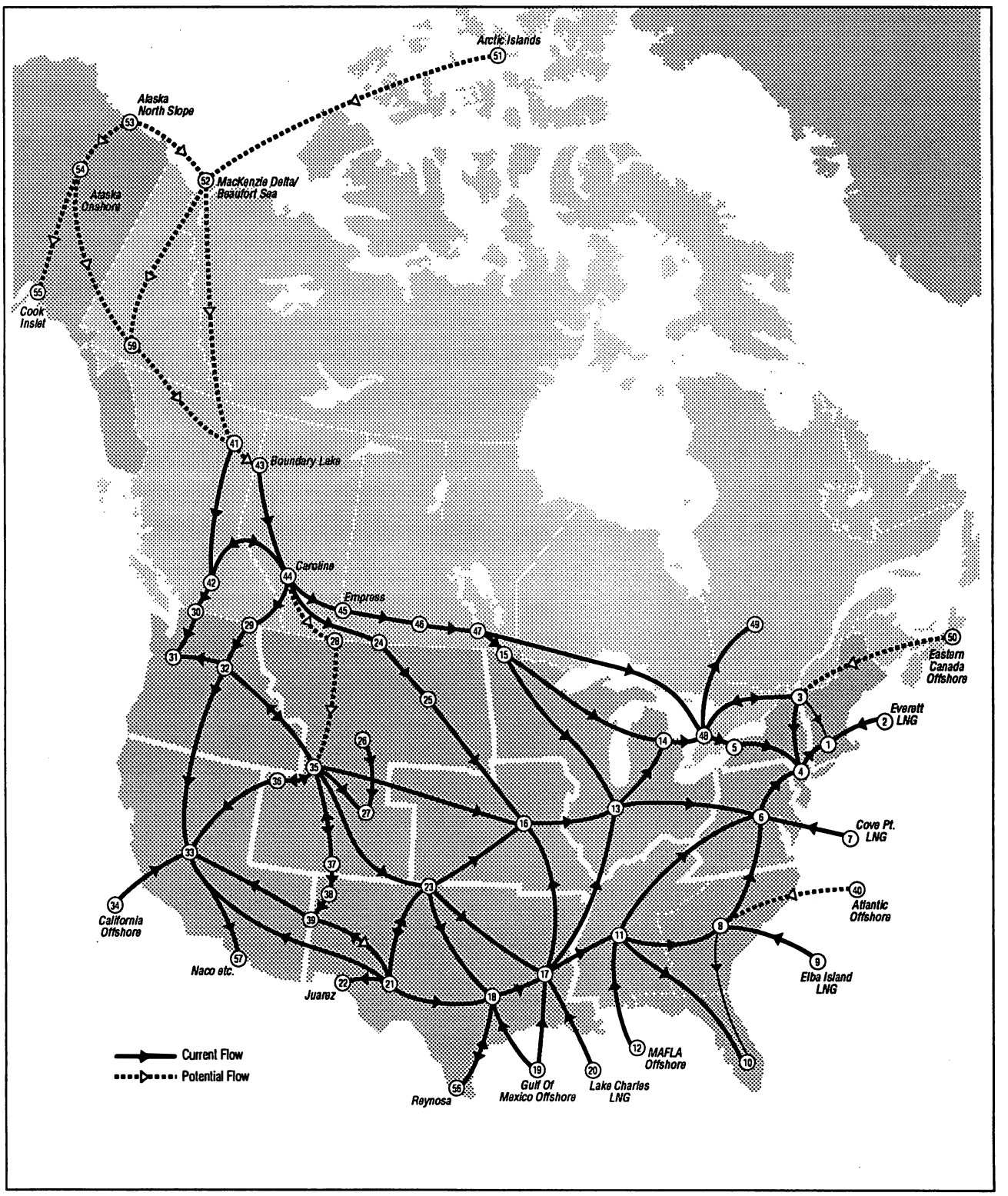


Figure 1-5. Lower-48 Major Pipelines and Demand Regions—EEA Model.

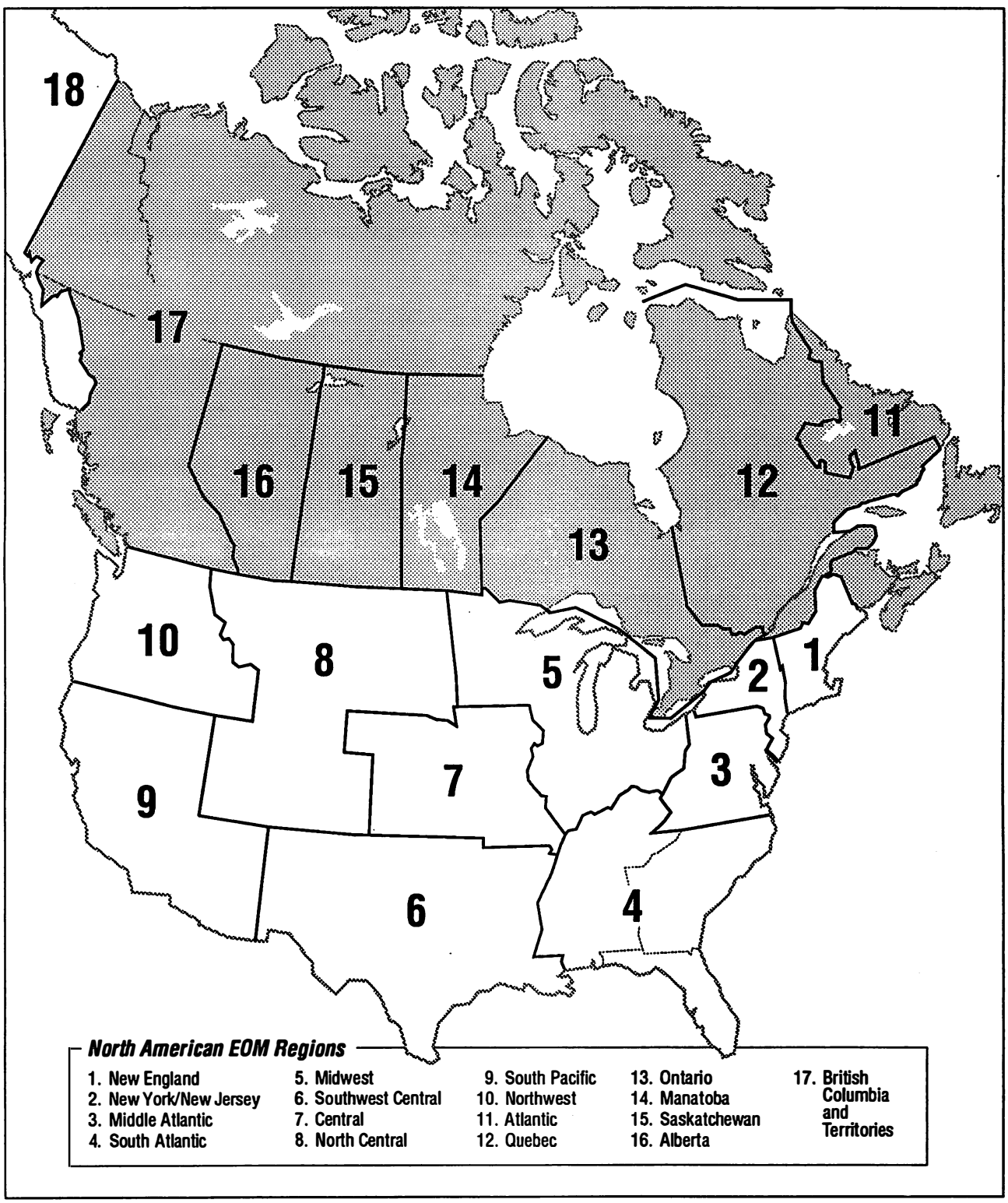


Figure 1-6. Major Pipelines and Demand Regions for Canada and Alaska—EEA Model.

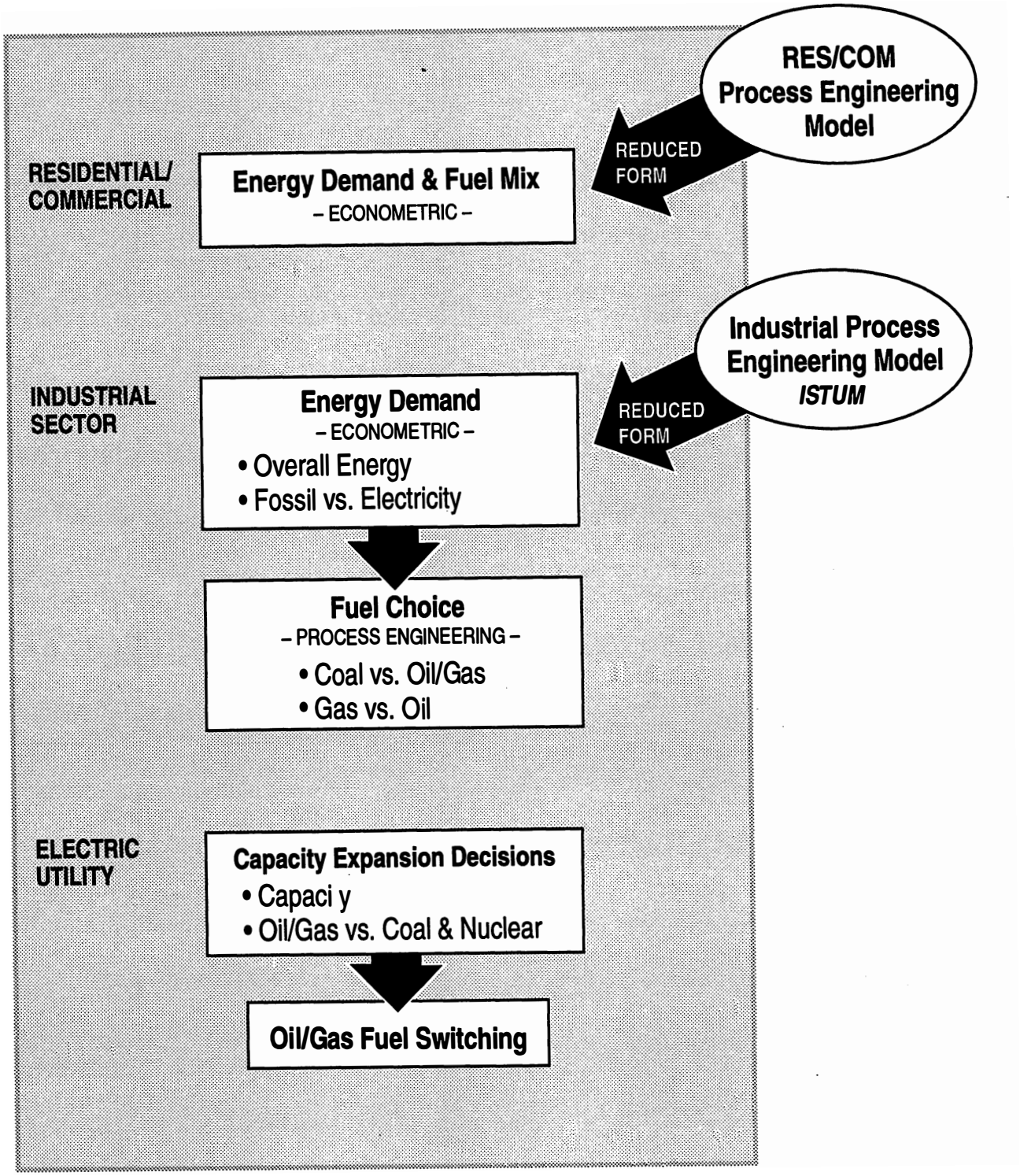


Figure 1-7. End-Use Sector Demand Models—EEA Model.

trends. The Industrial Sector Model combines econometric relationships between industrial energy input and economic output with a detailed process engineering model of the capital stock, fuel-firing capability, and fuel choices of industrial equipment. This model considers a variety of industry groups and functional end uses, accounts for emission regulations in the differing air quality regions, and simulates decision logic based on life cycle cost minimization. The Electric Utility Model covers different power plant types and load characteristics,

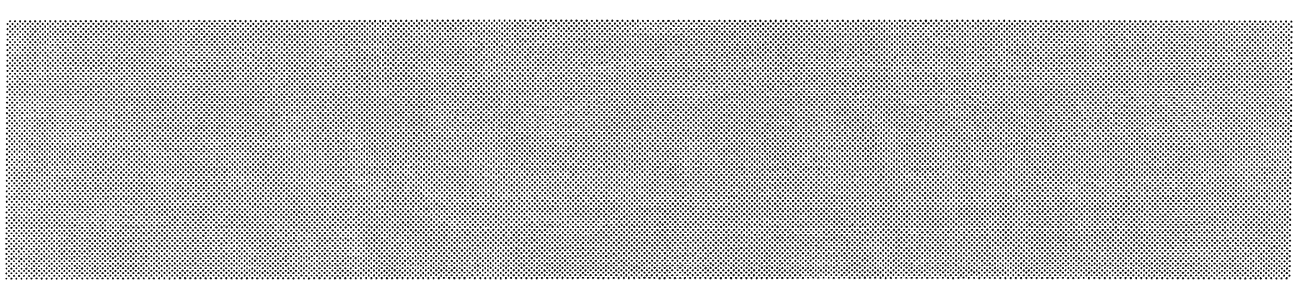
competes gas versus residual fuel type as determined by environmental regulations for existing units, and makes capacity expansion decisions from a slate of options that can be specified by the user. In all these markets, natural gas is competed endogenously against alternative fuels such as oil or coal. End-use prices for distillate and residual fuel oils are determined regionally, based on the input crude oil price forecast. Prices for residual fuel oil are distinguished for four classes of fuel quality, based on sulfur content. Similarly, coal of high and low sulfur content is priced regionally. Environmental compliance costs for oil or coal fuels, such as scrubbers, are explicitly accounted for in fuel choice decision making.

The pricing logic used in the EEA model is the result of both gas-on-gas and interfuel competitive pricing forces. The model determines the gas price that equilibrates natural gas supply and demand over time by solving for the clearing prices nationally, regionally, in the interruptible transport market, and in the firm/core markets. Although it is an annual model, seasonal price and volume variations are accounted for in the calculation of the annual averages. The key factor influencing prices is the degree of deliverability surplus and its impact on gas-on-gas competition, particularly when capacity utilization is low. When capacity utilization is high, fuel switching between gas and alternative fuels becomes a primary determinant of gas prices.

The suite of models from EEA require input assumptions for variables such as crude oil price and regional economic and energy growth rates. Rather than make arbitrary decisions regarding these variables, the NPC chose to contract with DRI/McGraw-Hill (DRI) to derive these parameters to be consistent with the two scenarios mentioned earlier in this chapter. DRI has a World Oil Model that is used to forecast the world oil supply/demand balance and prices. These results feed into their U.S. Macro, Regional, Energy, and Transportation Models, which work together to project the values used as inputs to the EEA models. The DRI models depend on input assumptions or "drivers" that were specified by the NPC as part of the scenario definitions. A description of the DRI models is included in Volume VI, Chapter Two.

Developing Recommendations for Increased Gas Use

Over the course of the study, constraints to the increased use of natural gas were identified from numerous sources. The Coordinating Subcommittee and task groups considered these constraints and potential recommendations for eliminating or reducing the effects of the constraints. The resulting recommendations are detailed in Volumes II through V and are summarized in Chapters Three through Six of this volume. Additionally, certain of the recommendations were collected into common categories designated as "Cross-Cutting Issues." These groupings included options and recommendations in the areas of: Environment, Technology, Reliability, Contract Diversity, Marketing, and Leadership. Chapters Seven through Twelve of this volume include a complete review of each of these issues.



CHAPTER TWO
MODEL PROJECTIONS

SCENARIOS

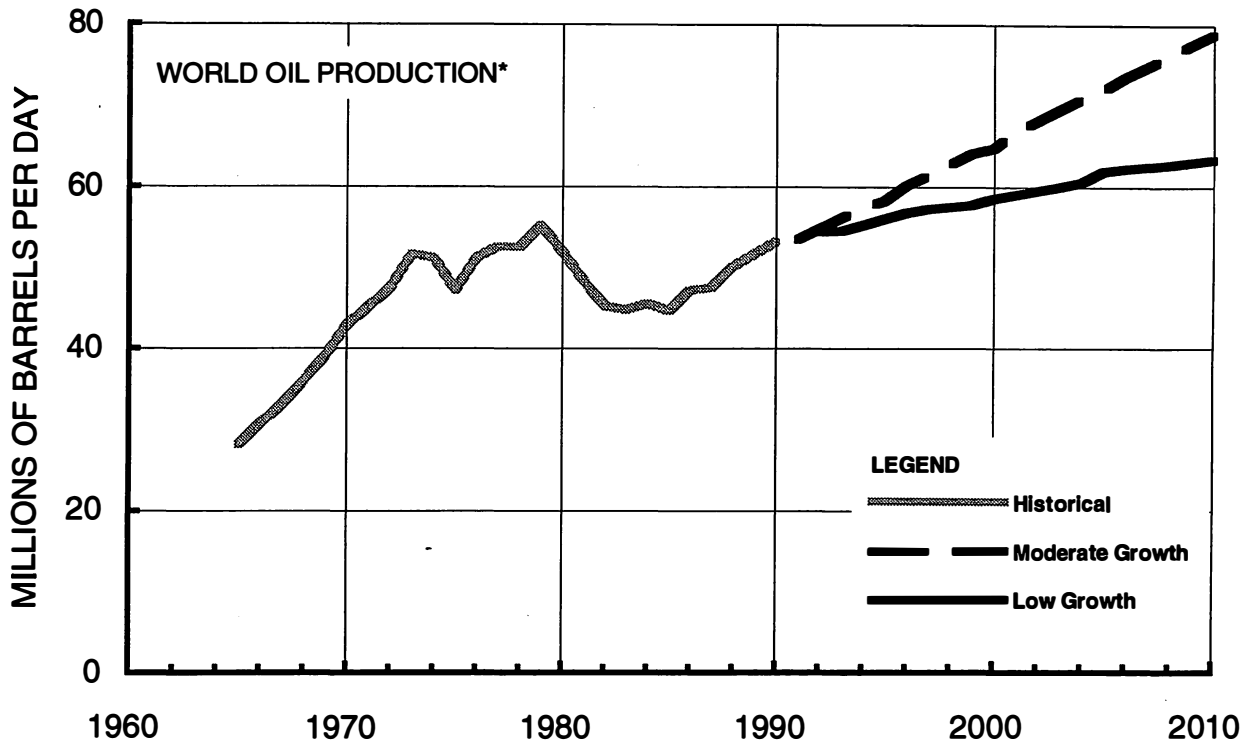
As discussed in Chapter One, this NPC study used two scenarios for analyzing potential future energy needs and the natural gas supply/demand balance for the United States. **The NPC did not attempt to develop a forecast of the future and the projections that are presented in this report should not be interpreted as such.** The purpose of the modeling effort was to provide a consistent framework for analyzing the supply potential, market opportunities, and transportation requirements under varying energy demand options, and to assess the sensitivity of the results to the uncertainties in the assumptions. The energy demand options were derived to be consistent with other assumptions concerning economic growth rates, consumption patterns, efficiency trends, availability of alternative fuels, etc. The two scenarios were selected to be sufficiently different so as to provide independent alternative views of future energy requirements. **Both scenarios are believed to be realistic and neither one is considered to be a "most likely" projection of future requirements.**

The first scenario assumes that the U.S. economy grows at an annual average rate of 2.4 percent between 1990 and 2010. Continued economic growth in world economies results in a growing world oil demand that requires significant future investments in exploration and production, resulting in real oil price increases over the 20-year period covered by the models. Energy conservation and the continuing introduction of more efficient technologies result in the projection of U.S. energy requirements somewhat below the level of many of the past forecasts, but overall energy growth is still significant.

In the second scenario, U.S. economic growth is assumed to average 2.0 percent annually over the 20-year period from 1990 to 2010. Additionally, it was assumed that aggressive conservation and efficiency initiatives would lower U.S. energy growth rates significantly below recent trends. A similar slowing of economic and energy growth rates in other industrialized countries reduces the growth rate for oil also and results in less capital investments being required to satisfy demand. Although the resultant lower energy prices provide a stimulus to economic growth and energy demand, it is not sufficient to offset the other decreases.

While no single term can adequately capture the diverse nature of these two scenarios, for convenience the first will be referred to as the "moderate energy growth scenario." Similarly, the second has been termed the "low energy growth scenario."

These two scenarios were modeled by DRI using the approach described previously and including the assumptions specified by the NPC (see Volume VI, Chapter Three). The results of these calculations are displayed in Figures 2-1 and 2-2. World oil prices for the moderate energy growth scenario increase continually over the period, with the U.S. refiners acquisition cost for crude oil (RACC)



* Excluding former Centrally Planned Economies.

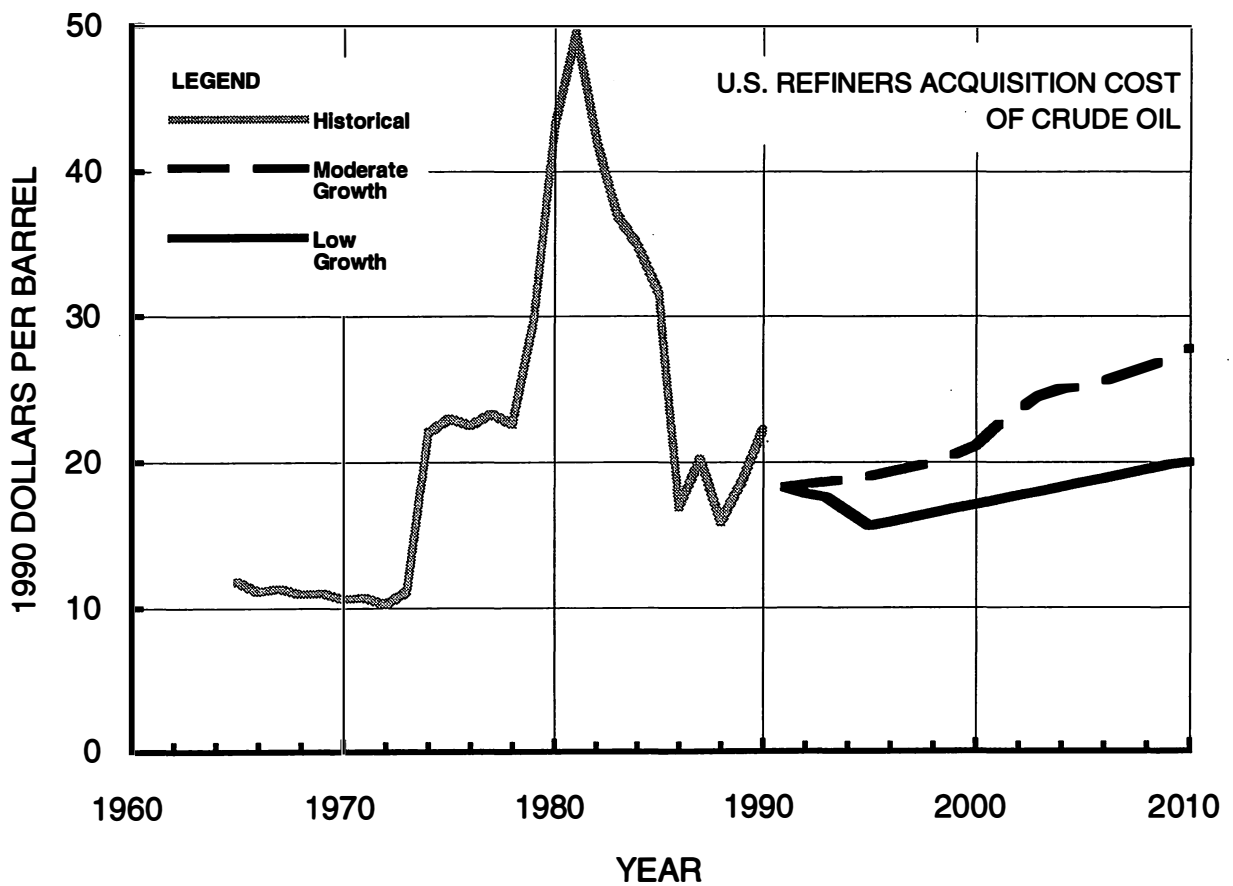


Figure 2-1. World Oil Production and Price—Moderate and Low Energy Growth Scenarios.

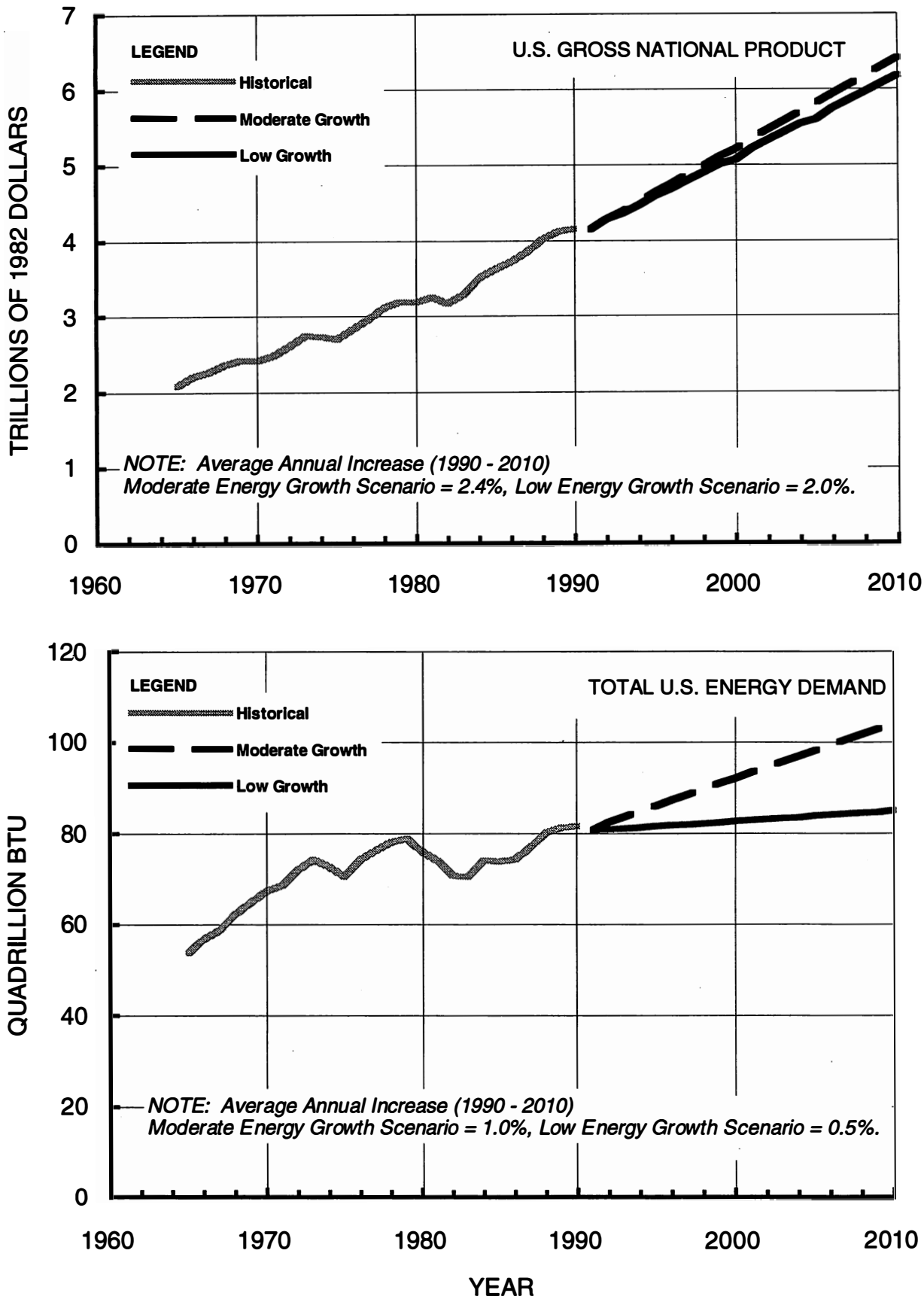


Figure 2-2. U.S. GNP and Energy Demand—Moderate and Low Energy Growth Scenarios.

reaching approximately $28 per barrel (1990$) by the year 2010. In the low energy growth scenario there is a near-term decline in real oil prices before gradually returning to the level of $20 per barrel (1990$). Total U.S. energy demand increases from the 1990 level of 80 quadrillion BTU (QBTU), growing by slightly more than 1 percent annually in the moderate growth scenario to 100 QBTU, and by slightly less than 0.5 percent annually to 88 QBTU in the low growth scenario.

Energy intensity (the ratio of energy consumed per unit of economic production) decreases by some 25 percent over the 20-year period in both scenarios. The growth rates for U.S. electrical energy consumption (modified slightly from DRI's results to be consistent with other NPC assumptions) are 1.6 percent and 1.3 percent annually for the moderate and low growth scenarios, respectively. These energy intensity and electrical energy demand trends are displayed in Figure 2-3. Volume VI, Chapter Four, contains the detailed output from DRI for each of these scenarios.

REFERENCE CASES

The NPC used the EEA Energy Overview Model to determine the sensitivity of the modeling results to various assumptions and as a guide to the selection of appropriate parameter values. The model was run both in its integrated form and using individual portions of the model on a stand-alone basis. The key model results are included in Volumes II through IV. This section will summarize the results of the two Cases, which have been termed the Reference Cases and which are consistent with the scenarios described previously. Chapter Three of Volume VI documents the NPC assumptions that drove the EEA modeling results; the outputs from the two model runs are included in Chapter Five of Volume VI. A brief summary of the assumptions and results for both Reference Cases is presented here.

Natural Gas Supply Projections

The Source and Supply Task Group worked with EEA's Hydrocarbon Supply Model in analyzing the natural gas resource base for the United States and Canada. Independent studies were made by the group (e.g., reserve appreciation of currently proved resources, import and export opportunities, and impact of various environmental initiatives) and by third parties contracted by the NPC (e.g., ICF Resources Incorporated for work on tight sands gas, technology, and environmental impacts; and Decision Focus Incorporated for North American gas movements as an aid in determining potential import levels). Key results from these analyses are summarized in Chapter Three and described in more detail in Volume II of this report.

The NPC resource estimate used in the Reference Cases is 1,295 trillion cubic feet (TCF) for the lower-48 states, representing current proved reserves plus the recoverable resource using technology projected to be applicable over the time period to 2010. The distribution of this volume among the various

TABLE 2-1

NATURAL GAS RESOURCE BASE FOR THE LOWER-48 STATES (Trillion Cubic Feet)

Proved Reserves	**160**
Conventional Resources	
Reserve Appreciation	203
New Fields	413
Subtotal	**616**
Nonconventional Resources	
Coalbed Methane	98
Shales	57
Tight Sands	349
Other	15
Subtotal	**519**
Total Resources	**1,295***

*Technically recoverable resource base as of January 1, 1991, assuming that current access moratoria expire as scheduled and incorporating technology advancement through 2010. Assuming various price levels with current and advanced technology, yields the following total resource estimates:

	Recoverable Resource Base (TCF)	
Price (1990$)	1990 Technology	2010 Technology
Unspecified	1,065	1,295
$3.50/MMBTU	600	825
$2.50/MMBTU	400	600

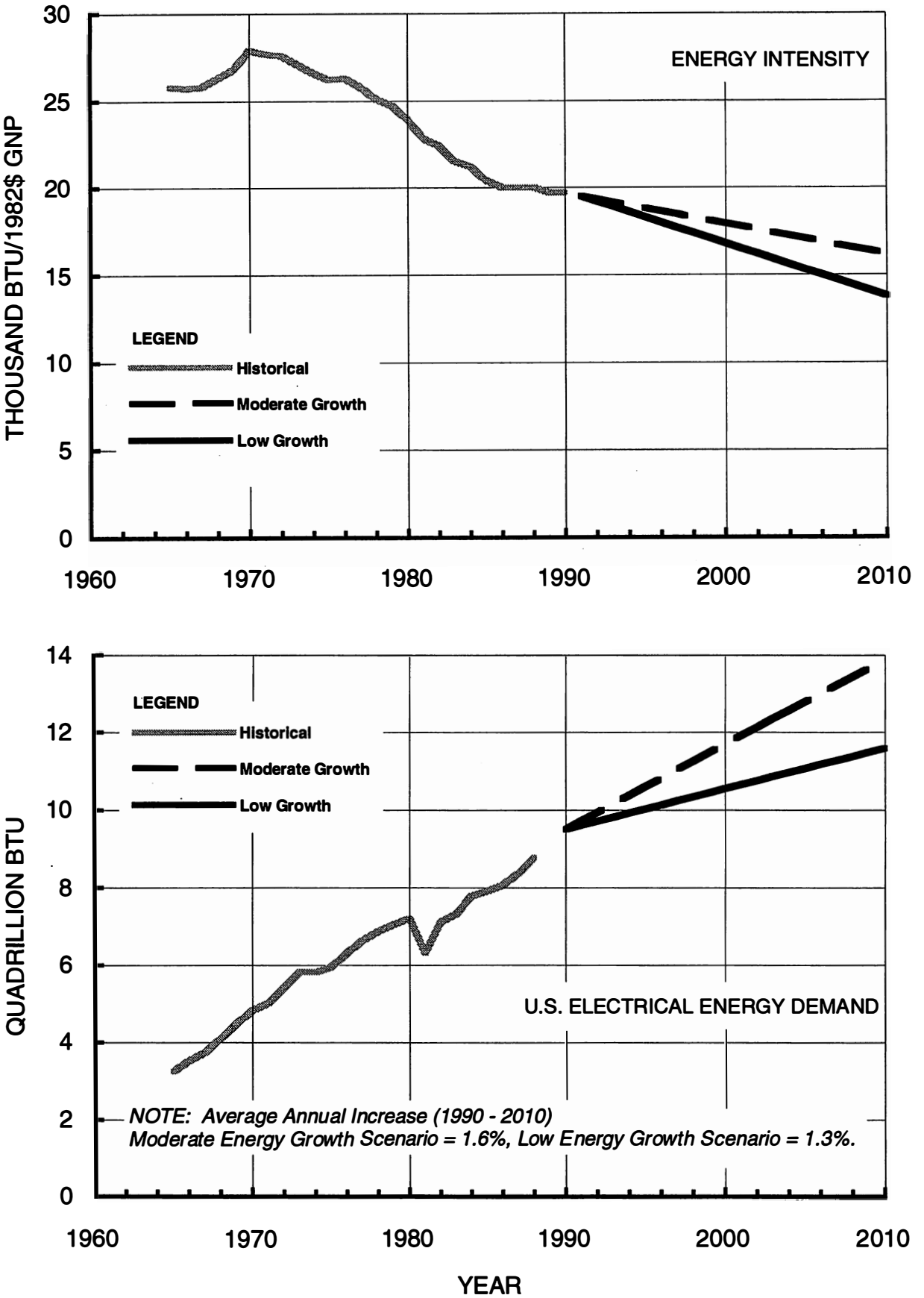


Figure 2-3. Energy Intensity and Electricity Demand—Moderate and Low Energy Growth Scenarios.

types of resources is shown in Table 2-1. No significant tax distortions or free trade restrictions are assumed that might bias natural gas supply type or source, e.g., new Section 29 tax credits are not extended beyond 1992. It is also assumed that existing offshore moratoria expire at the end of their current terms and that no further exploration or development access restrictions are enacted. Technology advances continue in line with the results of the detailed studies conducted by the NPC and ICF Resources, with the possibility of drilling improvements proceeding at a somewhat higher pace than determined historically. Sensitivity analyses of most of these assumptions are documented in Volume II. The supply assumptions do not change between Reference Cases 1 and 2; however, the resultant development of the resource base differs due to the slower pace of energy demand in Reference Case 2.

Projections of U.S. Energy Demand

Projections of total U.S. energy demand in 2010 for Reference Cases 1 and 2 are listed by sector in Table 2-2. Lower residential energy demand in Case 2 results primarily from the lower housing stock growth rate, with some slight additional reduction due to accelerated equipment efficiencies in Case 2 over Case 1. Commercial energy demand for Case 2 lags behind that of Case 1 due to a lower growth rate for commercial floor space. The largest difference between the Cases is in the industrial sector. This results from assuming that not only is the production growth rate slower in Case 2 but also that the energy efficiency gains will be much greater.

The purchased electricity growth rates that result from these different assumptions average 1.6 percent and 1.3 percent annually for Cases 1 and 2, respectively. The electricity growth rate was projected to be satisfied by a combination of new cogeneration units, repowering of existing oil/gas units, and construction of new coal and gas/oil generating capacity. New gas-fired units were assumed to be supplied at firm transport gas rates. Decisions on which type of capacity to add are discussed more thoroughly in Volume III, Demand and Distribution. Capacity additions used in the models through the year 2000 are consistent

TABLE 2-2

TOTAL U.S. ENERGY DEMAND
(Quadrillion BTU)

	1990	Reference Case 1 2010	Reference Case 2 2010
Industrial			
Fuel & Power *	16.8	21.3	16.5
Raw Materials	6.0	7.2	6.7
Subtotal	**22.8**	**28.5**	**23.2**
Residential	9.0	10.3	9.6
Commercial	6.5	8.2	7.7
Electric Losses †	20.0	25.0	22.8
Transportation ‡§	22.1	28.1	24.4
Total	**80.4**	**100.1**	**87.7**

* Includes lease and plant gas use.

† Energy losses during generation and transmission of electricity.

‡ Includes compressed natural gas vehicle demand and gas pipeline fuel.

§ Transportation sector energy projection prepared for the NPC by DRI.

with current announced plans as listed in the latest North American Electric Reliability Council publication. Beyond 2000, the model makes a decision on types of new units based primarily on the cost of the competing fuels, differing capital and operating costs for the new units, and applicable environmental restrictions.

Future price projections for low and high sulfur coal on a regional basis were derived by a consultant (Hill & Associates). In this projection, delivered prices for high sulfur coal decline in real terms over the forecast period while those for low sulfur coal increase slightly.

Delivered prices for natural gas are determined within the model each year; however, price *expectations* used in the decision logic for new electric generating units assume that future gas prices equilibrate with the applicable distillate or residual fuel oil price on an energy equivalent basis. (Implicitly, this reasons that a fuel buyer has more confidence in projections of crude oil price trends and assumes that natural gas prices will likely be capped by the competing liquid fuel prices.) It should be noted that fuel choices based solely on comparative economics as calculated by relatively simple model logic, even life-cycle economics, are not the sole determining factor in the decision-making process. Volume III discusses the various considerations that enter into the fuel choice decision, and concludes that projections made on the basis of the model calculations are most likely optimistic, although they represent a good target for the natural gas industry to pursue.

Modeling the U.S. Natural Gas Supply/Demand Balance — Case 1

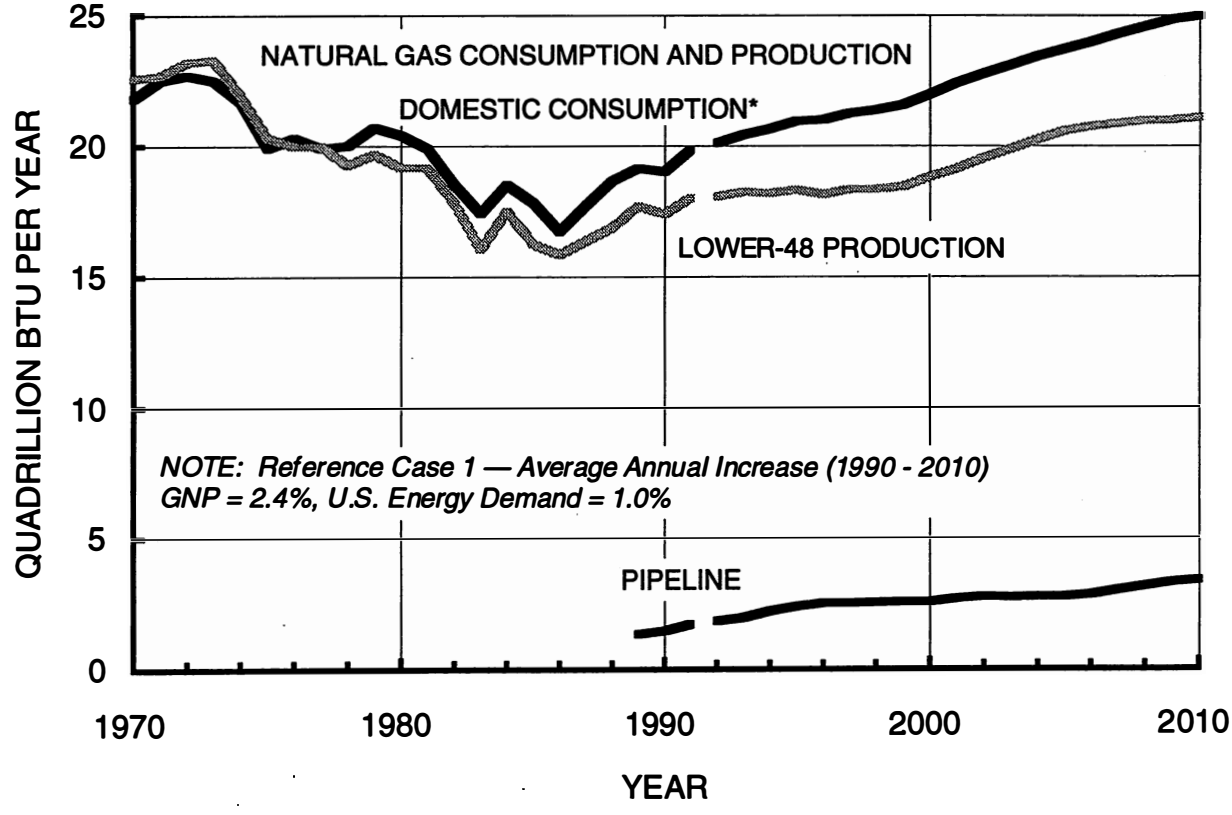
The characteristics of the Energy and Environmental Analysis, Inc. (EEA) Pipeline Model were described in Chapter One. The Transmission and Storage Task Group examined the regional flows required for the various supply and demand levels and derived algorithms for the cost and timing of adding new pipeline and storage capacity. The task group used a consultant (Jensen and Associates) to review current levels of deliverability and also performed independent analyses of peak seasonal and daily demand levels. These results are described in Volume IV and were utilized in the two Reference Cases.

The EEA model calculations with the NPC assumptions for Reference Case 1 project a natural gas domestic consumption that increases to some 25 QBTU by 2010. This is satisfied by a relatively flat domestic production level in the near term, with demand increases primarily accommodated by imports from Canada. Domestic production increases again in the latter part of this decade and by 2010 reaches a level of about 21 QBTU, with imports from Canada only rising slowly after about 2000. Exports to Mexico reach approximately 0.4 QBTU in the late 1990s, subsequently declining during the second decade to reach an import level of 0.1 QBTU. Liquefied natural gas (LNG) imports remain below 0.5 QBTU over the entire period. Calculated demand and price levels appear to be inadequate for developing the Alaskan North Slope gas resources or the northern frontier gas in Canada for domestic consumption prior to 2010. These projections are depicted in Figure 2-4.

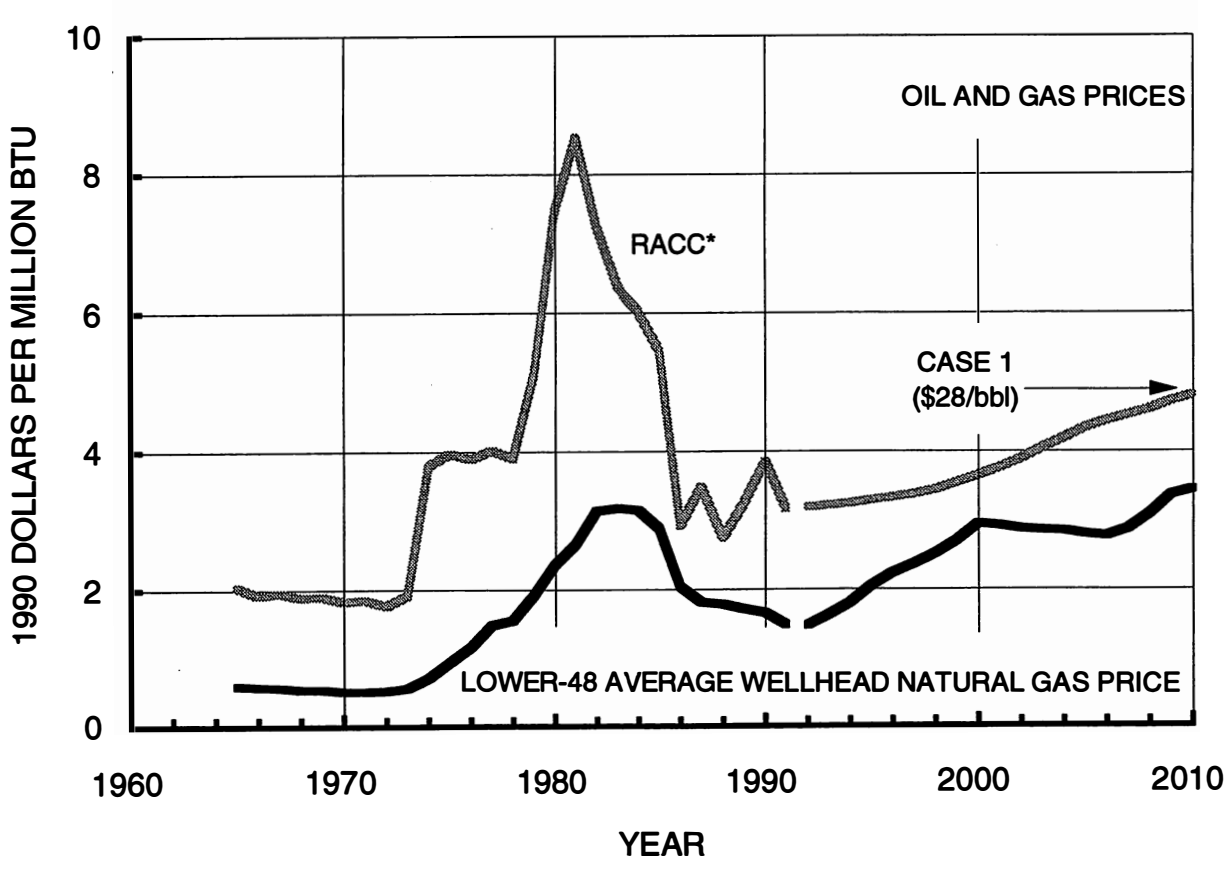
The lower portion of the figure shows the natural gas price trajectory calculated by the model, which is a prime determinant, of course, of the results just described. Average wellhead prices are calculated to increase to the level of about $2.75 per million BTU (MMBTU) (1990$) by the year 2000, as supply tightens due to reduced drilling activity in the near term and resultant reserve additions lag production levels. This situation reverses itself in the early part of the next decade and the model projects several years of declining price levels as additional reserves are developed; prices do not decrease to current levels in spite of the added drilling activity since the gas reserves being developed at that time are generally more expensive to bring on line, e.g., deep tight gas.

It is realistic to expect that additional forces will cause gas prices to fluctuate in the future, as they have in the past, although the details of that fluctuation are beyond the ability of any model to project. Price and supply volatility can be anticipated as the industry progresses through the current transitional period and adjusts to changing regulations and competitive forces.

Figure 2-5 displays the mix of energy sources projected to be used for combustion purposes in 2000 and 2010 as contrasted with 1990. All fuels grow somewhat during the first



* Includes lease, plant, and pipeline fuel, plus exports.



* RACC = Refiners Acquisition Cost for Crude oil (U.S. average).

Figure 2-4. Natural Gas Consumption, Supply, and Price—Reference Case 1.

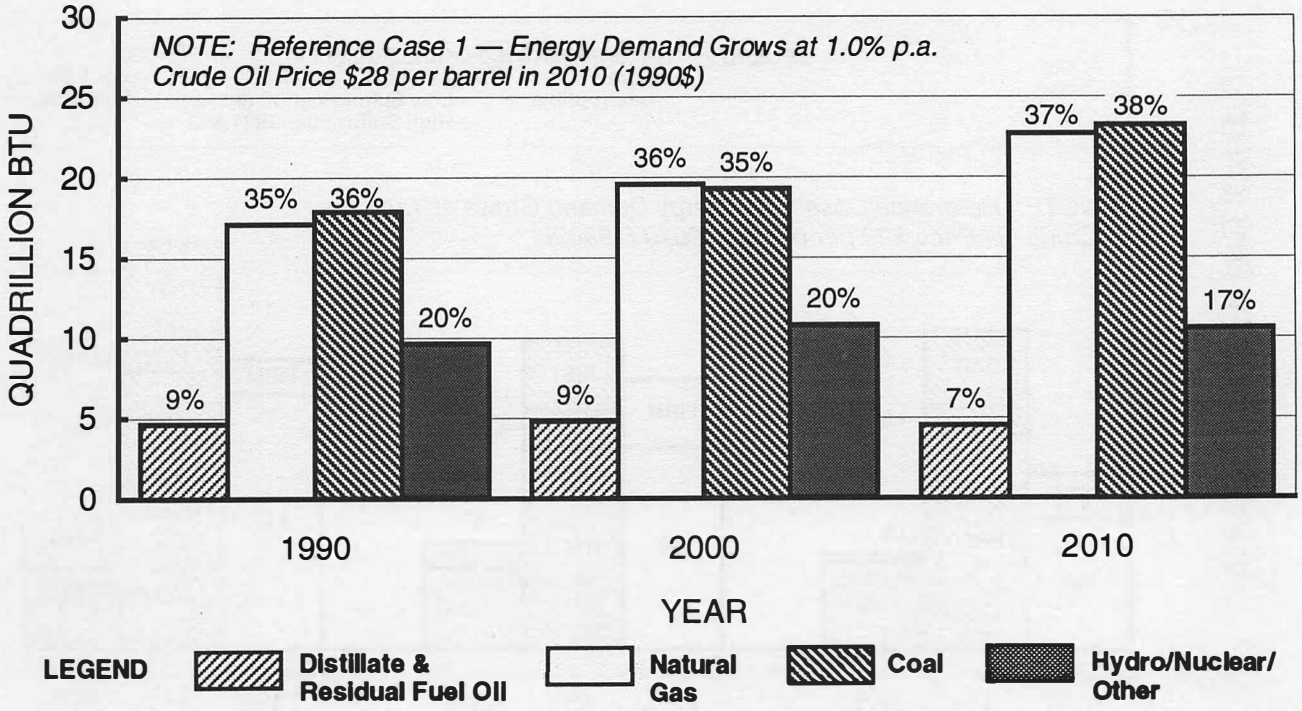


Figure 2-5. Primary Energy Consumption and Market Share—Reference Case 1.
(Excludes Coking Coal, Oil Feedstocks, and Liquid Transportation Fuels; Gas Data Exclude Lease/Plant Fuel, Transmission Fuel, and Exports)

decade, with natural gas increasing more rapidly than the others. All market sectors contribute to the increase in natural gas consumption with the utility market generating the greatest demand increase. In the second decade, however, the trend reverses and coal consumption increases more rapidly than natural gas, with the other fuels actually experiencing a slight decline in both absolute and relative terms. As demonstrated in sensitivity cases described in the next section of this chapter, accelerated technology effects and efficiencies that act to reduce the delivered price of gas have a significant impact on the proportion of the energy market that can be potentially captured by natural gas. **The importance of continuing efforts to reduce the cost of the delivered gas cannot be overemphasized.**

The relative relationships between the competing energy prices are shown in Figure 2-6, which contrasts delivered fuel prices to a large end user such as a utility, and Figure 2-7 for the residential/commercial sector. Distillate and residual fuel oil prices are calculated from the input crude oil price track. Four different residual fuel oil slates are used in the model, although for clarity the electric utility comparison shows only the 0.3 percent and 1.3 percent sulfur residual fuel oils. The coal prices are national averages computed from the regional prices and calculated consumption levels. The gas prices to the utility are derived by the model following the logic described earlier. As mentioned earlier, delivered fuel prices are only one factor in determining a utility's decision on the type of plant to construct; other variables that influence the decision are presented in Volume III.

For the residential/commercial sector, average natural gas prices, calculated by the model, increase due to the increased wellhead price of gas from reserves that are more costly to develop, partially offset by the economies of scale in the transmission and distribution systems from higher volumetric throughputs; the net increase in delivered gas price (1990$) is slightly more than 1 percent annually over the 20-year period. While natural gas consumption increases somewhat in this sector, larger relative gains in use of electric energy results in natural gas losing market share in the combined residential/commercial sector. Delivered gas prices to the industrial sector are intermediate between the electric utility and residential/commercial sectors, dependent on consumption levels, and are not displayed here.

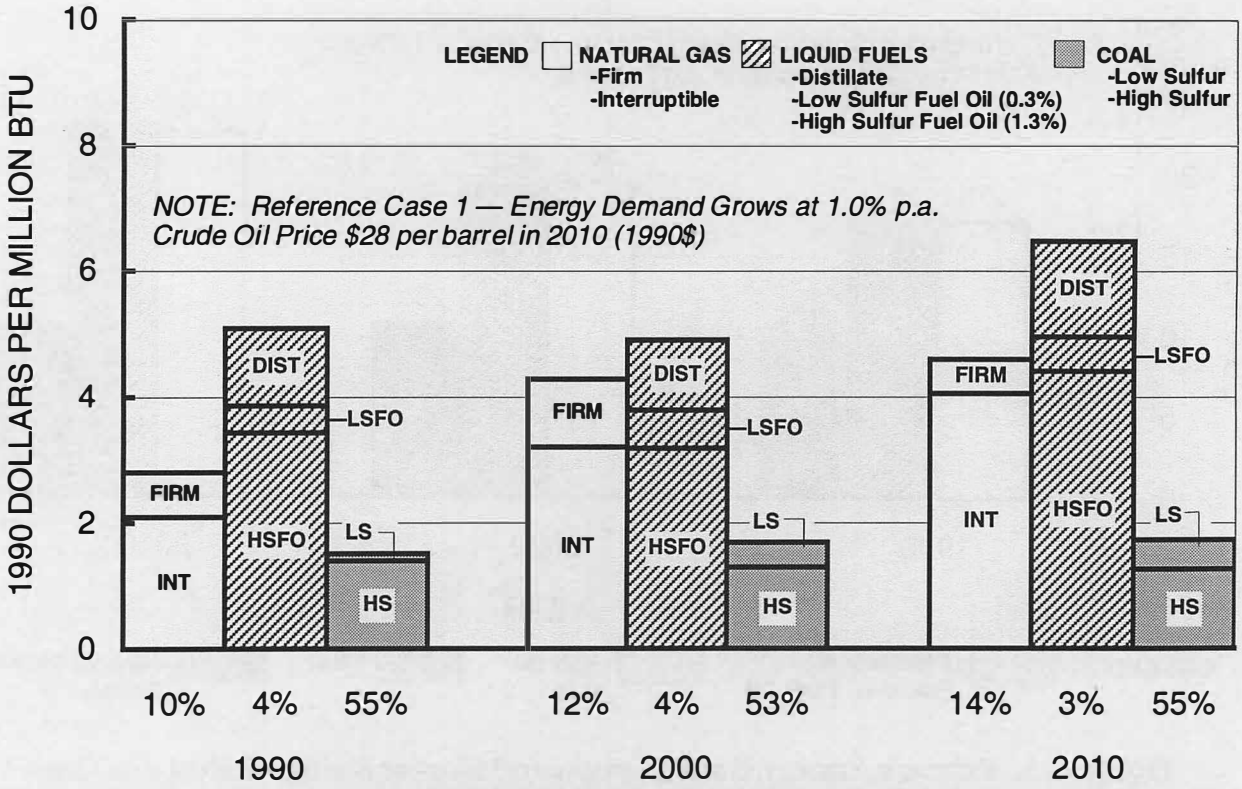


Figure 2-6. Electric Utility Market Average Burnertip Price and Market Share for Natural Gas, Liquid Fuels, and Coal—Reference Case 1.
(Nuclear, Hydro, and Renewables make up the balance of shares)

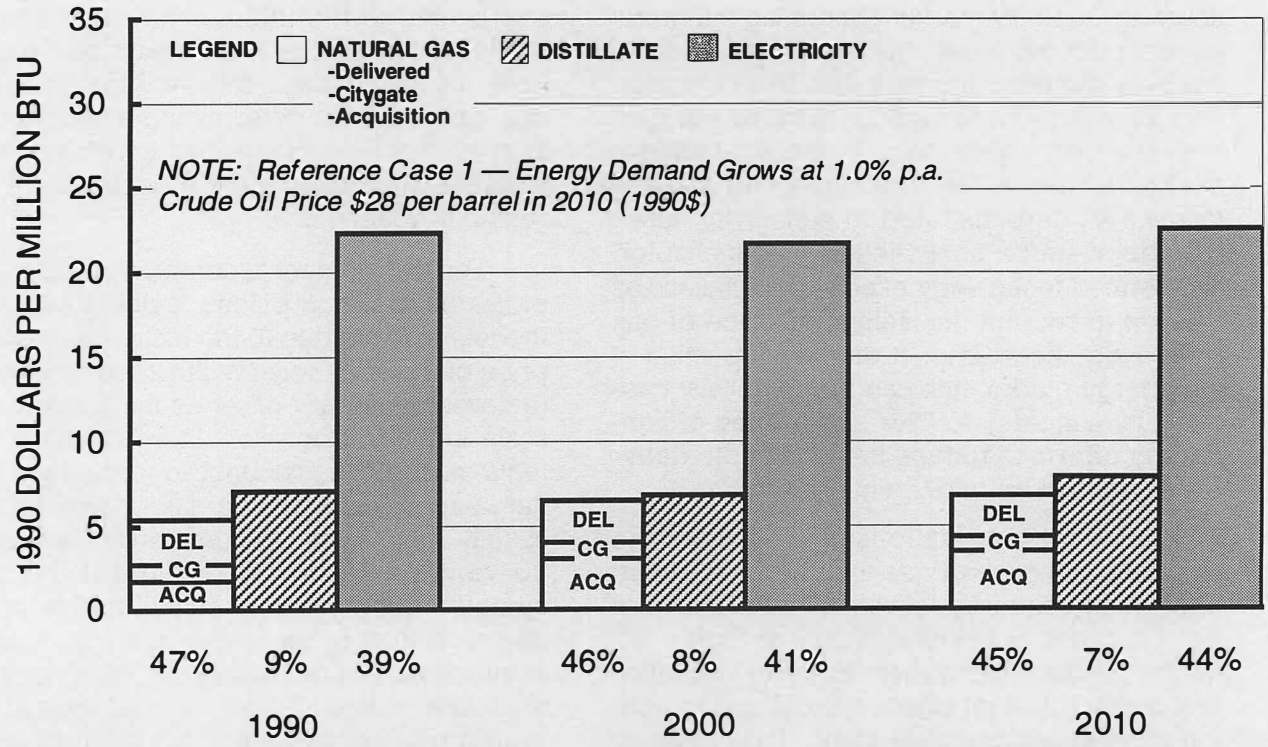


Figure 2-7. Residential/Commercial Market Average Delivered Price and Market Share for Natural Gas, Distillate, and Electricity—Reference Case 1.
(LPG and Coal make up the balance of shares)

Model outputs for all sectors are included in Volume VI, Chapter Five.

Modeling the U.S. Natural Gas Supply/Demand Balance — Case 2

Figures 2-8 to 2-11 are similar depictions for Reference Case 2, which has lower overall energy demand levels and relatively flat crude oil prices. For this Case, domestic natural gas consumption levels are calculated to remain at essentially 20 QBTU annually for the decade of the 1990s before gradually rising to 21 QBTU by 2010. Lower-48 production fluctuates between 16 and 18 QBTU over the period and pipeline imports remain below 3 QBTU, all from Canada; LNG imports do not exceed 0.5 QBTU annually during the forecast period. Computed average wellhead gas prices rise to about $2.50 per MMBTU (1990$) by the year 2000 and only increase another $0.25 per MMBTU over the following ten years. The influence of crude oil prices is evident in this case as the wellhead average equilibrates to about 80 percent of the RACC price on a BTU equivalent basis and competition from residual fuel oil moderates the gas price and consumption increases.

The primary energy consumption share pattern differs somewhat from Case 1, as natural gas consumption in Case 2 never exceeds coal consumption on either an absolute or a relative basis. This is the consequence of declining energy demands in the industrial sector, which result in less gas consumption, nearly offsetting the gains in the other market sectors, particularly over the next decade. The low residual fuel oil prices cause switching away from natural gas in spite of the discounting evident in the interruptible transport gas market. Residual fuel oil consumption in Case 2 exceeds that of Case 1 in 2000 and nearly equals it in 2010 even though overall demand levels are substantially less in Case 2, especially in the industrial market sector.

Comparison of Natural Gas Demand Between Case 1 and Case 2

Table 2-3 compares the calculated natural gas demand by sector in 2010 between the two Reference Cases. The apparent growth in the residential sector over the 1990 consumption is misleading due to the influence of weather on the 1990 level (4.5 QBTU); the residential consumption in 1989 was 4.9 QBTU. As discussed in Volume III, this sector has only small growth potential due to increased efficiencies offsetting the additional residential hookups. The commercial sector has growth potential in both Cases, although the growth is not projected to exceed one quadrillion BTU of additional consumption over the next 20 years.

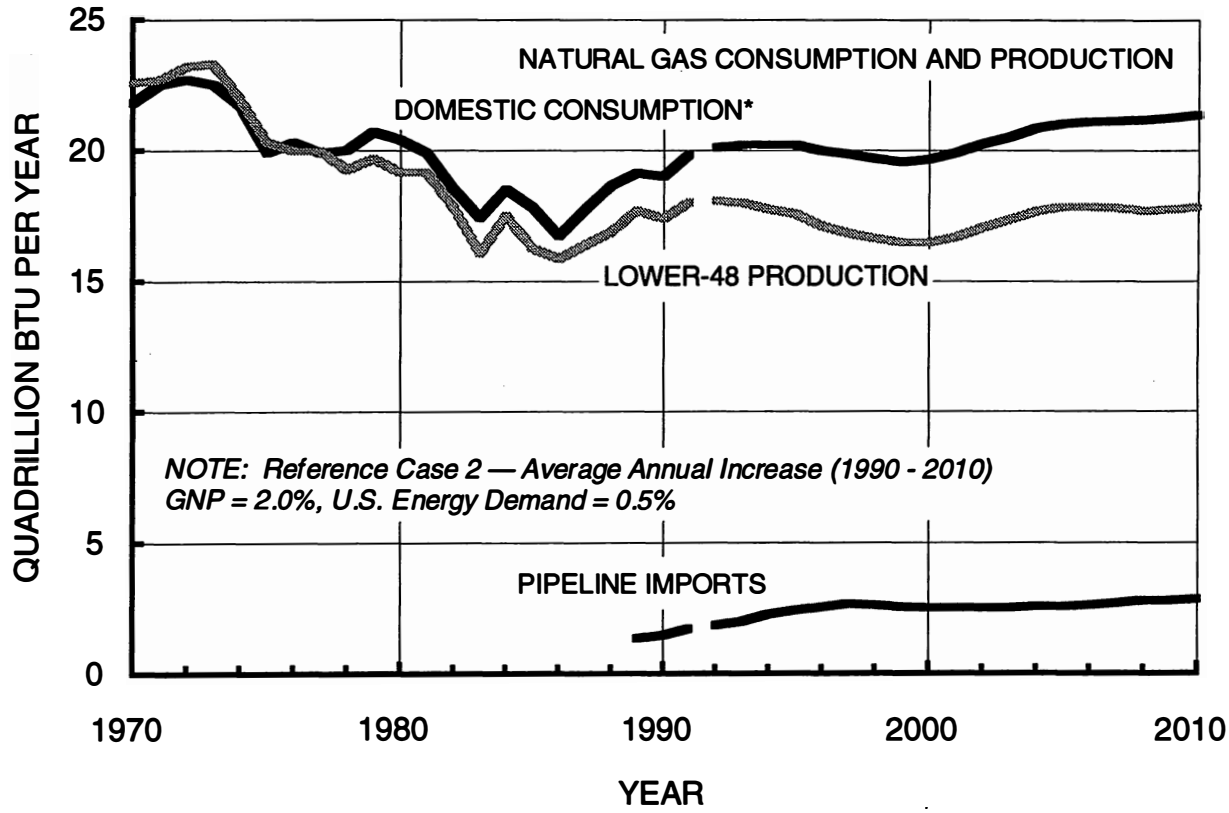
Growth of natural gas consumption in the industrial sector is highly dependent on assumptions regarding industrial growth rates, industrial mix changes, and the effect of efficiencies that might be introduced into this sector. Consumption of natural gas by this sector is calculated to grow by nearly two QBTU for Case 1, but it actually declines by nearly one QBTU in Case 2. Electric utility demand, as referenced in nearly all projections of future energy needs, is projected as the major growth market for natural gas. As mentioned earlier, however, capturing the additional market potential of the 2 to 2.5 QBTU projected in the Reference Cases will be a significant challenge for the natural gas industry.

Natural Gas as a Vehicular Fuel

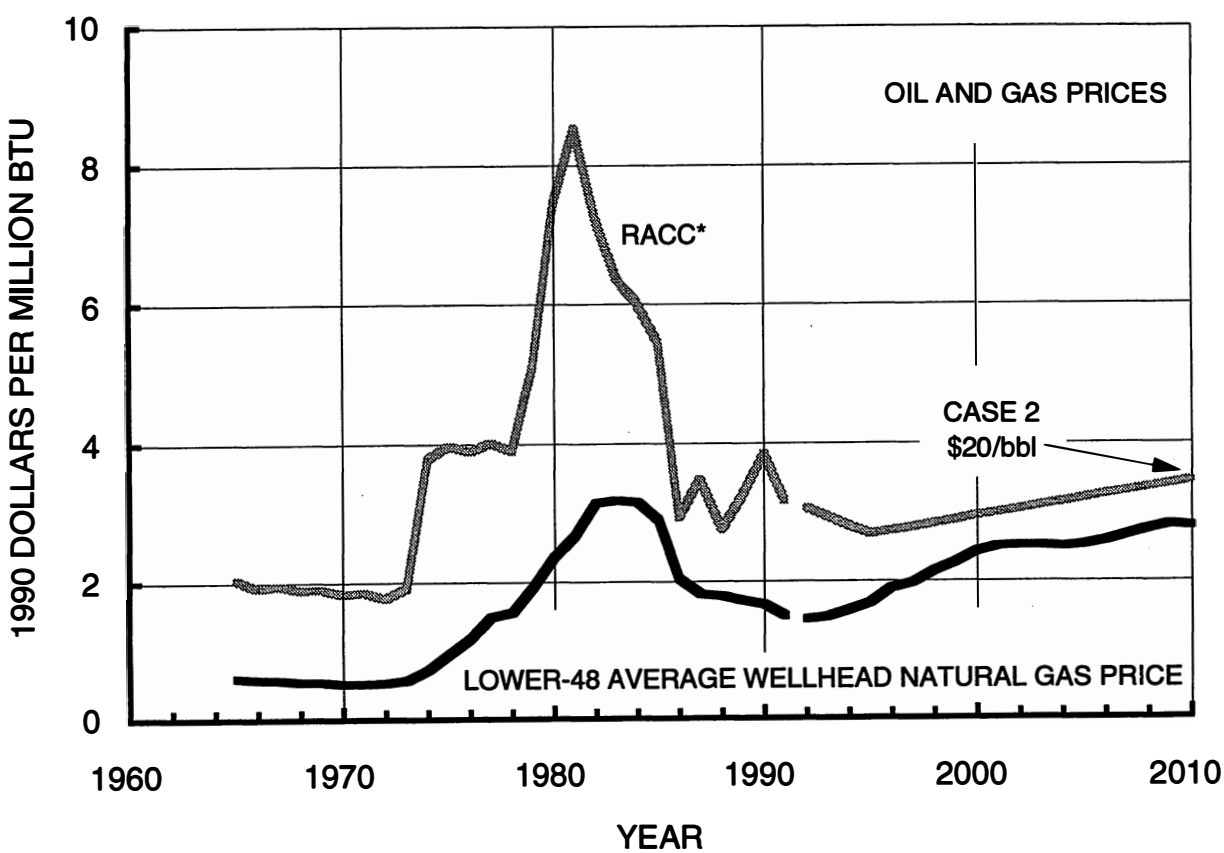
The potential market for natural gas as a vehicular fuel is not calculated by the EEA models; however, it was estimated by the NPC participants and included in the total commercial sector consumption numbers quoted above. For these Reference Cases, the annual consumption in natural gas vehicles (NGVs) by 2010 was projected to be some 140 billion cubic feet (BCF). This market level is based on an estimate of the number of clean-fuel vehicles required by mandated programs, with reasonably achievable penetration rates assumed for compressed natural gas versus other clean fuels in each of the vehicle groups. The consumption level could be significantly higher if compressed natural gas can achieve a higher penetration of the market or if clean-fuel vehicles exceed the current mandates. This is discussed in Volume III and included in one of the Option Cases presented in the next section.

Reference Case Projections versus History

Figure 2-12 offers another view of the two NPC Reference Case projections compared to



*Includes lease, plant, and pipeline fuel, plus exports.



* RACC = refiners acquisition cost for crude oil (U.S. average).

Figure 2-8. Natural Gas Consumption, Supply, and Price—Reference Case 2.

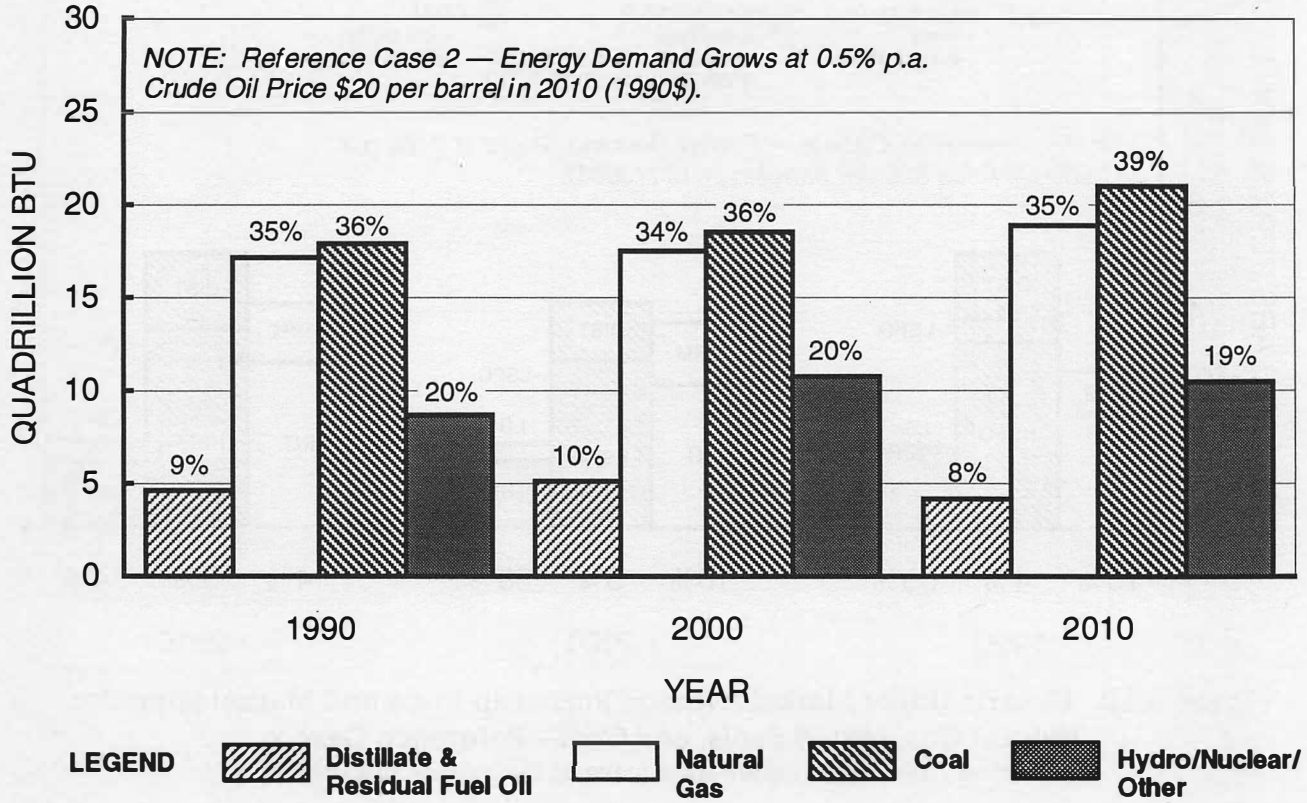


Figure 2-9. Primary Energy Consumption and Market Share—Reference Case 2.
(Excludes Coking Coal, Oil Feedstocks, and Liquid Transportation Fuels; Gas Data Exclude Lease/Plant Fuel, Transmission Fuel, and Exports)

TABLE 2-3

LOWER-48 NATURAL GAS CONSUMPTION
(Quadrillion BTU per Year)

End-Use Sectors	1990	Reference Case 1 2010	Reference Case 2 2010
Residential	4.5	4.9	4.7
Commercial	2.7	3.5	3.1
Industrial	7.0	8.9	6.1
Electric Utility	2.9	5.4	4.9
Total End Use	**17.1**	**22.7**	**18.8**
+ Lease/Plant Fuel	1.1	1.3	1.1
+ Transmission Fuel	0.6	0.9	0.7
+ Exports/Misc.	0.2	0.2	0.7
Total Consumption	**19.0**	**25.0**	**21.3**

Note: Totals may not agree due to rounding.

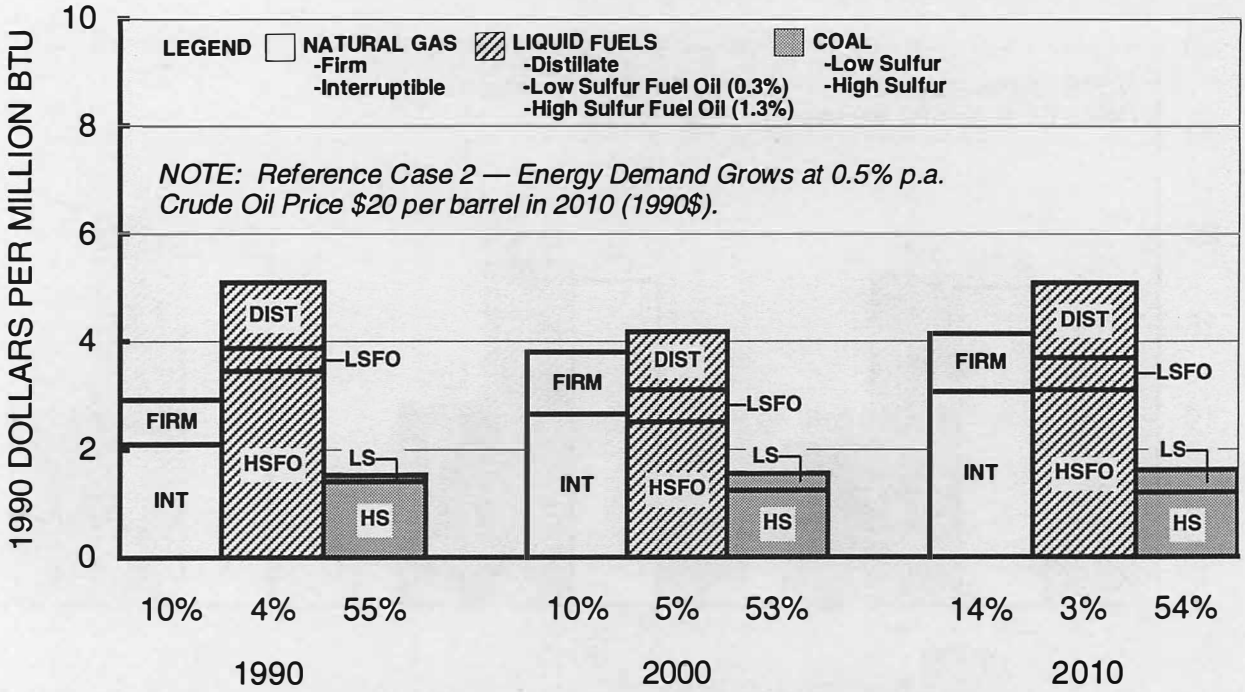


Figure 2-10. Electric Utility Market Average Burnertip Price and Market Share for Natural Gas, Liquid Fuels, and Coal—Reference Case 2.

(Nuclear, Hydro, and Renewables make up the balance of shares)

the past 40 years of history. Natural gas consumption is plotted versus price (in constant 1990$) in five-year increments. The 20-year period from 1950 to 1970 was characterized by surplus producing capacity and explosive demand growth as the interstate system expanded to bring the surplus gas to the growing markets. It included interstate wellhead price controls and a tightly regulated transmission and distribution system. The period from 1970 to 1990 was turbulent with concerns about a perceived scarcity of gas, imposition of com-

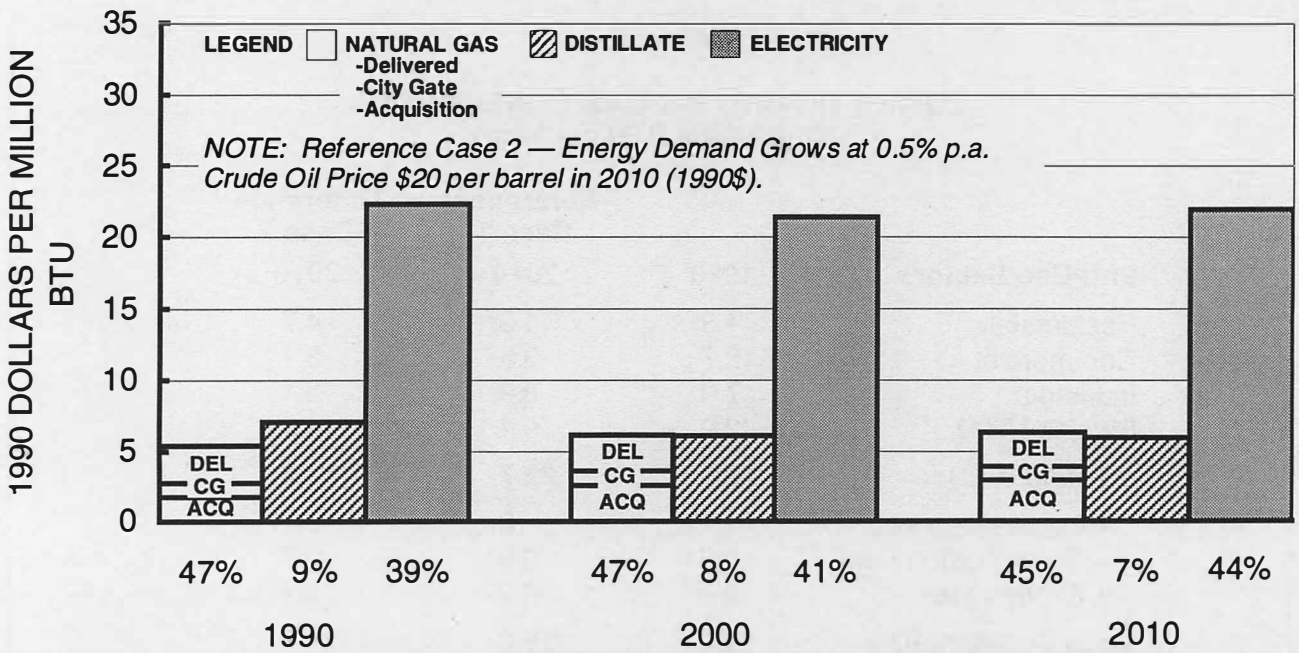


Figure 2-11. Residential/Commercial Market Average Delivered Price and Market Share for Natural Gas, Distillate, and Electricity—Reference Case 2.

(LPG and Coal make up the balance of shares)

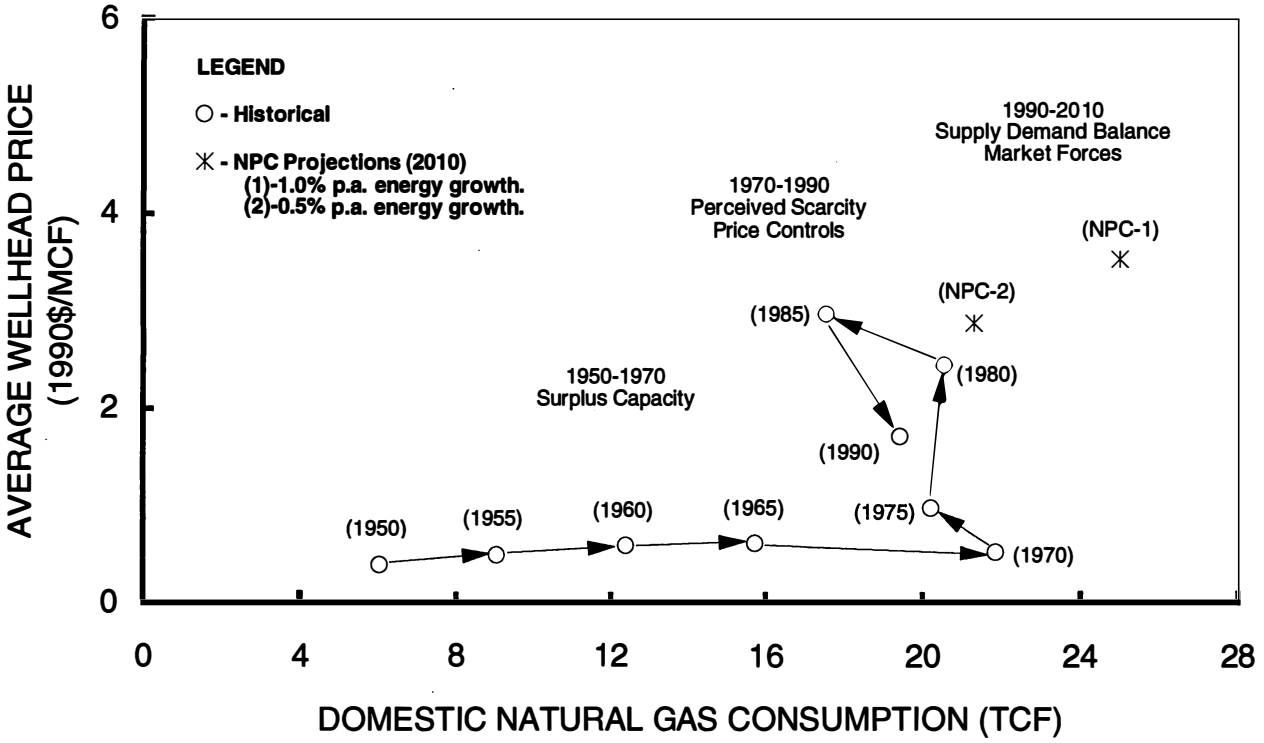


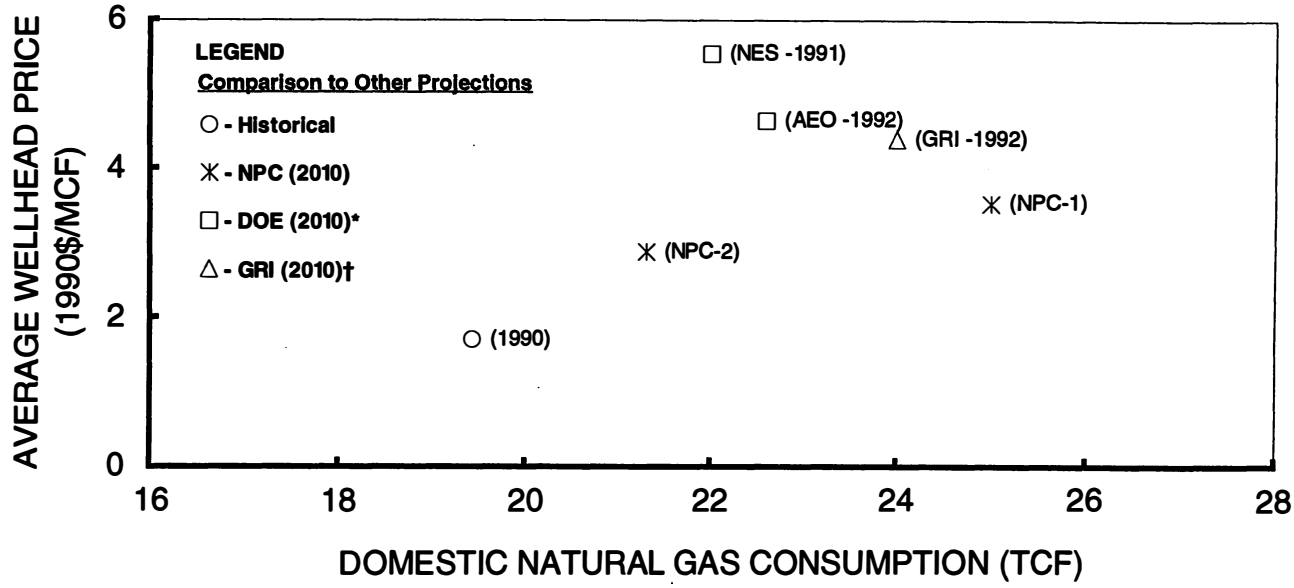
Figure 2-12. Natural Gas Wellhead Price vs. Consumption—Historical and NPC Projections.

plex wellhead price controls, and ultimately a collapse of the high prices as the market reacted to low oil prices, high gas prices, and a growing awareness of an abundance of natural gas available to the domestic markets.

The 1990-2010 time frame is assumed to be one of a gradual transition to market forces dominating consumer choices and supply coming more in balance with demand. Wellhead prices are projected to increase over that time frame due to the need to produce from higher cost resources under more stringent environmental conditions, with technology advances only partially able to offset the real cost increases.

Figure 2-13 illustrates the period from 1990 to 2010 and compares the results of the two NPC Reference Case calculations with other projections from the literature. Essentially all of these forecasts project wellhead prices for natural gas by 2010 that are higher than the NPC calculations, even though the consumption levels are generally lower. The preliminary Gas Research Institute Baseline for 1993, which was generated contemporaneously with this NPC study, is in close agreement with NPC Reference Case 1 and has many similar characteristics. The Gas Research Institute also considered an alternative case of reduced energy demand and lower oil prices and the results for natural gas price and consumption in 2010 essentially overlay NPC Reference Case 2.

The purpose of describing these and other model results is not to attempt to project that these are likely outcomes for the future. Rather, they are a convenient and consistent way to evaluate alternatives and quantify market potentials under a variety of assumed conditions, including the sensitivity of the projections to uncertainties in the assumptions. This is elaborated on in the following section, which presents the results of three sensitivity calculations and two Option Cases. Volumes II through IV contain additional information on the different sensitivities, but these three were selected because of their relevance. They include the effect of uncertainties in the key supply assumptions and the potential to further increase market demand by lowering delivered gas costs. The Option Cases represent conditions where the natural gas industry is successful in exceeding the assumptions contained in the Reference Cases or where it falls short of those assumptions. These results provide a qualitative representation of



* DOE — Department of Energy:
NES — National Energy Strategy, Technical Annex 2, Department of Energy, 1991/1992.
AEO — Annual Energy Outlook 1992 — With Projections to 2010, Energy Information Administration, Jan. 1992.
† GRI — Gas Research Institute, 1992 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand.

Figure 2-13. Natural Gas Wellhead Price vs. Consumption— NPC and Other Forecasts.

the uncertainties in the estimates of future supply and demand and the opportunities for exceeding (or falling short) of the calculated potentials.

SENSITIVITY AND OPTION CASES

A large number of preliminary runs were made with the EEA models as an aid to selecting appropriate operating parameters and to gain insight into the sensitivity of various assumptions. (This was particularly true for the Hydrocarbon Supply Model and these results are described in more detail in Volume II, Source and Supply.) Three sensitivity runs have been selected to be included in this summary. Additionally, calculations were made for the net effect of options that would act to increase or decrease the supply/demand results of the two Reference Cases. Selected outputs from the Reference Cases, Sensitivity Cases, and Option Cases are included in Volume VI. **Note that while the Option Cases were examined for their impacts on both of the Reference Cases, Sensitivity Cases were examined only relative to Reference Case 1. The decision to examine sensitivities against only a single Reference Case was solely based on study costs and should not be interpreted as a preference for the particular Reference Case as a more likely view of the future; Case 1 was selected for testing as it was thought to be the one where the sensitivities were likely to have their largest effects.**

Results of Sensitivity Cases

Supply Uncertainties Related to Geology and Technology

Important assumptions on the supply side are related to geological uncertainty and projections on the rate of advance of technology in the future. The former is particularly meaningful in estimating the undiscovered resource potential, while the latter affects exploration expenditures, production costs, and recovery efficiencies. As discussed in detail in Volume II, the most likely value for the undiscovered conventional resource potential for the lower-48 states was estimated as 413 TCF. A range of plus and minus 40 TCF on either side of this estimate was selected for inclusion in these Sensitivity Cases. While this is not the maximum uncertainty associated with the undiscovered conventional resource, it is believed to represent a reasonable range for the **uncertainty in the estimate of the most likely value** for the

undiscovered conventional potential. Also, the rate of technology advance over the past 20 years, particularly as related to drilling costs, was evaluated along with an estimate of its likely impact in the future on costs and recovery volumes. For these Sensitivity Cases, it was assumed that technology impacts could be 25 percent higher or lower than the values used in the Reference Cases.

Table 2-4 shows the combined effects of these geological and technical uncertainties on wellhead prices, natural gas supply, and lower-48 production in the year 2010. (Values in the earlier years are proportionately less than for 2010 and are negligibly different from the Reference Cases before 1996.) While the impact on wellhead prices is certainly significant, ranging between $0.40 and $0.70 per MMBTU, the cumulative effect on production and consumption over the 15-year period from 1996 to 2010 is even more significant. Total gas consumption in the Positive Supply Sensitivity Case is 4.5 QBTU greater than Reference Case 1 and domestic production is some 7.7 QBTU higher with imports reduced by 2.4 QBTU. (The import reduction is not the difference between consumption and domestic production since additional gas is used as lease and plant fuel, transmission fuel, etc., which is not included in the consumption value.)

The lower price for natural gas stimulates a small amount of additional primary energy consumption (61.6 QBTU vs. 61.0 QBTU in 2010) with the net increased gas consumption being primarily in the industrial and utility sectors (2.3 and 1.1 QBTU cumulative over the 15 years, respectively). The residential and commercial sectors show cumulative increased gas use of about 0.5 QBTU each. **While total gas consumption is increased, the net value of the wellhead price reduction, assuming no change in the transmission and distribution costs, is in excess of $100 billion in total reduced gas costs to the customers over the 15 year time period!** Additionally, residual fuel oil consumption is reduced by some 100 million barrels over that time period, representing over $2 billion less in import costs. The reduced cost for natural gas imports is even greater; not only is the volume reduced by 2.4 QBTU, a direct saving of over $6 billion, but the technology advances also are assumed to be applied in Canada and serve to reduce the costs of the gas that is imported, yielding a net reduction in import gas costs of more than $20 billion.

These reduced costs are the net effect of the more rapid technology advances and the additional undiscovered potential gas volumes, although technology advances contribute most of the cost reduction. This emphasizes the importance of investing in technology that will result in additional volumes of natural gas coming available at reduced costs. On the flip side, the Negative Supply Sensitivity Case is almost a mirror image of the Positive Case and approximately the opposite effects are evidenced, with slower technology advances and reduced exploration potential significantly increasing natural gas costs to the customer and resulting in additional imports of both natural gas and residual fuel oil.

Impact of Delivered Gas Costs

In the Reference Cases it is assumed that higher volumetric throughputs and some efficiency increases will approximately offset transmission fuel and labor costs that are projected to advance at rates in excess of normal inflation, thus maintaining overall delivery costs approximately constant in real terms. (In Reference Case 1, both transmission and distribution costs per MMBTU, as reflected in local distribution company gas tariff prices, decline in real terms by about 0.5 percent annually between 1990 and 2010.) The NPC study participants believe that opportunities exist to reduce costs further over the entire natural gas system, from production through delivery, including transaction costs across each segment of the system. An analysis was made of the impact of reducing costs on a portion of the system.

As discussed in more detail in Volume IV, a sensitivity case was run with transmission costs reduced below the Reference Case values. This may require some form of incentive rate design to stimulate the additional advances. The Incentive Rate Sensitivity Case looked at the potential impact of reducing transmission costs by some 2 percent annually from the costs in the Reference Case. While the effects shown in Table 2-4 may appear to be relatively small, a close comparison of the numerical outputs (see Volume VI) reveals some significant impacts of these cost reductions.

TABLE 2-4

SELECTED RESULTS FROM SENSITIVITY AND OPTION CASES (All Results are in the Year 2010)

Case Description	Average Lower-48 Wellhead Price (1990$/MMBTU)	Total Consumption (QBTU)	Lower-48 Production (QBTU)
NPC Reference Case 1	3.43	25.0	21.1
NPC Reference Case 2	2.78	21.3	17.8
Sensitivity Cases			
Positive Supply (vs. Case 1)	2.74	25.9	22.2
Undiscovered Volume +40 TCF	(-.69)	(+0.9)	(+1.1)
Technology Advances 25% Faster Than Reference Case			
Negative Supply (vs. Case 1)	3.84	24.2	20.0
Undiscovered Volume -40 TCF	(+.41)	(-0.8)	(-1.1)
Technology Advances 25% Slower Than Reference Case			
Incentive Rate (vs. Case 1)	3.44	25.3	21.3
Transmission Costs Decline 2% Per Year Over Ref. Case	(+.01)	(+0.3)	(+0.2)
Option Cases			
Upside Option (vs. Case 1)	2.96	26.7	22.1
500 BCF More NGV Potential in 2010	(-.47)	(+1.7)	(+1.0)
500 BCF More Gas Cooling Potential in 2010			
Supply Technology Advances 25% Faster Than Ref. Case			
Transmission Costs Decline 2% Per Year Over Ref. Case			
Downside Option (vs. Case 1)	3.91	23.1	18.8
50% of Growth Potential in Utility and NGV Markets	(+.48)	(-1.9)	(-2.3)
Supply Technology Advances 25% Slower Than Ref. Case			
High Environmental Compliance Costs on E&P Operations			
Upside Option (vs. Case 2)	2.52	23.3	19.5
Same as Above	(-.26)	(+2.0)	(+1.7)
Downside Option (vs. Case 2)	3.03	19.6	16.0
Same as Above	(+.25)	(-1.7)	(-1.8)

Delivered gas prices in 2010, as contrasted with wellhead prices, are calculated to be some $0.17 per MMBTU less than the Reference Case. This could stimulate nearly 2 QBTU of additional natural gas consumption over the 15 years to 2010, most of which results from domestic reserve additions and production, at essentially no net increase in average wellhead prices. Gas demand is potentially higher in the residential, commercial, and industrial markets as a result of the lower delivered cost. This could reduce the electricity demand and defer construction of new generating plants. (Electric utility generating capacity additions through 2010 are calculated to be some 4 percent or 8 megawatts less than in the Reference Case.) Although gas would be more competitive in the utility market at the lower price, the reduced electricity demand results in a net decrease in the consumption of gas by the utilities. Overall, though, there is a net calculated increase of some 0.3 QBTU per year by 2010, with a total consumption increase of nearly 2 QBTU, cumulatively. **The lower delivered gas prices due to the 2 percent annual reduction in transmission costs could result in a net cost reduction to the customer in excess of $30 billion over the 15 year period to 2010!**

While no specific areas have been targeted for achieving these cost reductions, the magnitude of the impact provides the incentive to investigate opportunities in more detail. This case only investigated the impact of reductions in transmission costs and did not include an estimate of the effect of lowering natural gas distribution costs; however, significant impacts on net delivered cost and consumption can be anticipated if distribution costs could be similarly reduced.

Results of Option Cases

In addition to investigating individual sensitivities related to uncertainties in various assumptions, several runs were made with the EEA Energy Overview Model to determine the potential impact of either exceeding or falling short of the conditions modeled in the Reference Cases. Upside and Downside Options were assumed to be the same for both Reference Cases, although their effects manifested themselves differently in each Case. While these have been termed "Upside" and "Downside" Cases, it would be wrong to infer that they represent the limits or bounds for the natural gas industry. They are intended to represent directionally the magnitude of the impact that might be expected relative to the Reference Cases if the alternative outcomes were to occur. In the Upside Case this represents achieving all of the Reference Case results and expanding the supply and demand opportunities beyond the Reference Case assumptions. On the Downside, the Cases provide some indication of the impact of not being able to achieve all of the advances or improvements assumed.

Upside Option Case

In the Upside Option Case, it was assumed that the major opportunities for increasing natural gas demand, relative to the Reference Cases, were provided by NGV and gas-cooling technologies. These market areas are discussed in Volume III, Demand and Distribution. The Reference Cases assumed that use of natural gas in the vehicular market would increase to about 140 BCF per year. This represents a reasonably achievable penetration of compressed natural gas versus other clean fuels in each of the vehicle groups in the currently mandated programs. It was estimated that increased usage in both fleet and private vehicles could result in an additional consumption of 500 BCF per year by 2010. The other key advance that could result in additional gas use involves significant penetration of gas cooling technologies, primarily in the commercial sector. For the Upside Option Case, an increase of 500 BCF per year by 2010 was also assumed for gas cooling. (This reduces the demand for electricity in the commercial sector and these offsets were included in the model.) On the supply side, technology advances were included that exceeded the Reference Case advances by 25 percent, as discussed in the previous section on sensitivities. Similarly, improvements were included that resulted in reduction of transmission costs by 2 percent annually relative to the Reference Cases.

Table 2-4 shows the results of the Upside Option Cases versus the two Reference Cases. Compared to Reference Case 1, the Upside Option Case shows increased gas use of some 1.7 QBTU per year by 2010, the majority of which comes from increased domestic production.

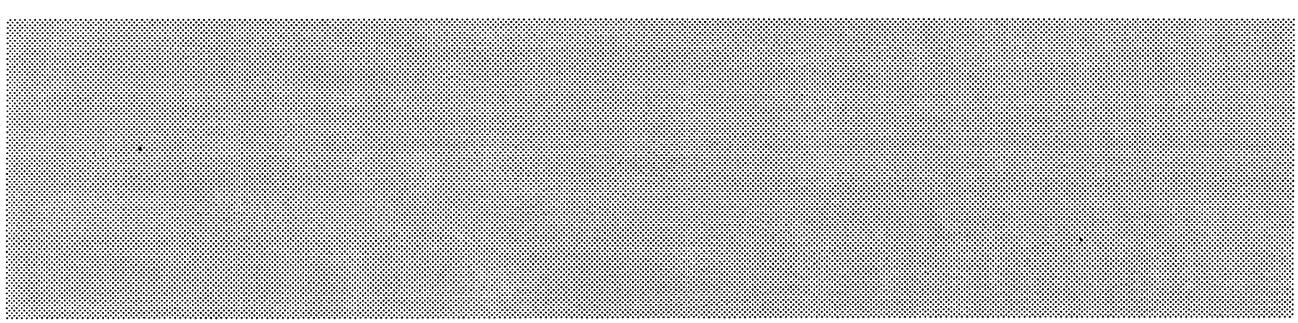
Technology advances that reduce the wellhead price, along with the transmission cost reductions, combine to reduce the delivered cost to the customer. Thus, in addition to the approximately one QBTU of increased use of natural gas in NGVs and gas cooling, the lower gas prices stimulate additional consumption, primarily in the industrial sector although slight increases also occur in the other sectors. Overall electrical demand is down due to the use of gas cooling; however, the lower gas prices maintain a relatively constant natural gas consumption level in the utility area.

The consumption impact versus Reference Case 2 is somewhat greater than against Case 1, partially due to the fact that Case 2 had a calculated natural gas consumption level nearly 4 QBTU less than Case 1 in 2010. The most significant difference is in the increase in domestic gas production, which accounts for nearly all of the calculated additional gas used in 2010. Effects on wellhead prices are less, in spite of the technology improvements and increased consumption, mainly due to the wellhead price in 2010 being some $0.65 per MMBTU (1990$) lower in Reference Case 2 versus Reference Case 1.

Downside Option Case

The assumptions in the Downside Option Cases differ significantly from those in the Upside Case. On the Demand side, it was assumed that natural gas would not be as successful in penetrating the potential new markets, specifically the electric utility and vehicular markets contained in the Reference Cases. (The gas cooling market is only significant in the Upside Option Cases described above.) Growth in consumption in each of these markets was assumed to be only 50 percent of what was calculated in the Reference Cases, e.g., if the use of natural gas in the utility sector increased from 2.9 QBTU in 1990 to 5.4 QBTU in 2010 (Reference Case 1), the Downside Option Case assumed it would only increase to about 4.2 QBTU. Similarly, the NGV potential was reduced from 140 BCF per year in 2010 to 70 BCF per year, with proportionate reductions in the prior years. On the supply side, it was assumed that technology advances would proceed 25 percent slower than what was included in the Reference Cases. Also, higher E&P environmental compliance costs were assumed, as discussed in detail in Volume II. No improvements were assumed in the transmission costs relative to the Reference Cases.

The summary of these results bears several similarities to the Upside Options Cases, albeit the direction of the changes is reversed. The most significant difference is in the level of domestic production. Relative to both Reference Cases, the reduction in domestic production is greater than the change in overall gas usage, indicating a net increase in imports even though total consumption is down. This is primarily an effect of the increased environmental compliance costs as discussed in Volume II, Source and Supply.



CHAPTER THREE
SUPPLY AVAILABILITY

OVERVIEW

This study by the National Petroleum Council, and particularly its assessment of the resource base and its availability, finds abundant domestic resources in place, an advancing level of technology making those resources available, and additional volumes available through trade within North America and elsewhere. The opportunity to make natural gas a secure and more widely utilized fuel available at moderate prices is substantial. To take advantage of this opportunity, however, will require a vital natural gas industry operating in a market-driven environment with full public recognition of the costs and benefits of environmental regulation, continuing technology emphasis, and access to resources for exploration and development. The Council firmly believes this can be accomplished to the mutual benefit of the nation and all involved in natural gas production, transportation, marketing, and consumption.

Additionally, the industry must learn from past mistakes and build on demonstrated performance. Past fears of limited reserves brought on in part by the industry's lack of foresight must be addressed and corrected. Steps toward deregulation have only recently progressed to the point that the industry can demonstrate its potential to respond in a competitive market. Concerns that arise during transition to a fully market-driven structure must be acknowledged and overcome.

Invariably, the fortunes of natural gas have been impacted by those of oil, whose swings during the last two decades have been unprecedented. Even though gas and oil markets now function independently, the persistence of an excess of gas supply (the so-called "gas bubble") and a maturity of domestic oil reserve opportunity are contributing together to a scale-back of North American producer activity. Despite the economic basis for such change, there is concern in the market as to potential implications for future gas supply reliability. Price volatility, as seen in the form of monthly wellhead spot price changes, adds to the concern. Although sharp swings, such as those seen in 1992, may be largely the temporary product of transition to a competitive market, all participants are looking for ways to minimize individual exposure.

Within this setting, and at the explicit request of the Secretary of Energy, the Source and Supply analysis of this study was conducted under the following mission statement:

- ***Evaluate supply aspects of the potential for natural gas to make a greater contribution to the nation's energy balance.*** A credible estimate is required of the recoverable resource base and economic long-term supply including conventional, non-conventional, and import alternatives. Uncertainties of a geologic, technical, and regulatory nature must be recognized. Historical perspective and vision for the future are required to identify industry and government initiatives to reduce barriers, provide confidence in supply, and enhance future natural gas availability.

KEY SOURCE AND SUPPLY FINDINGS

During the course of this study, the supply potential for the U.S. market has been examined and recommendations have been made supporting improved supply utilization. Through in-depth technical assessment of the resource and delivery potential, use of a sophisticated modeling tool and specific focus on key parameters including technology, environmental regulation, and contracting practices, the NPC has arrived at the following findings:

- The United States has a vast and diverse recoverable natural gas resource base that will continue to grow with time and technology. Anticipating such growth through 2010, the NPC estimates the technically recoverable resource at 1,295 trillion cubic feet (TCF) for the lower-48 states alone. Potential Canadian, Mexican, Alaskan, and liquefied natural gas (LNG) supply are also backed by large resources. Contrary to past perceptions, the natural gas resource base itself is not (and should not be viewed as) a limit to expanded gas usage. Industry must take the lead in ensuring that this message is articulated and adopted in the market. The Department of Energy (DOE) is urged to join in promoting this assessment. It should be used as the basis for future federal and state policy determination.

- Natural gas supply from these resources can be made competitively available to meet foreseeable demand growth if proper market signals, technology advancement, and environmental management practices are forthcoming. For example, under Reference Case 1 (the moderate energy growth scenario), market driven, competitive pricing for natural gas can bring forth sufficient supply to sustain current uses and attract new customers. Case 1 shows that a 25 percent increase in demand to 25 quadrillion British thermal units (QBTU) by 2010 is supportable.

- Model results indicate that supply is not likely to be sustainable for the long term at wellhead gas prices typical of recent years. However, they do indicate that supply can be sustained, and even increased, at prices that nevertheless remain competitive with expected user alternatives. Case 1 indicates that a Texas Gulf Spot gas price growing to $3.50 (1990$) per million BTU (MMBTU) by 2010 would stimulate sufficient supply to competitively meet a growing energy demand in a growing oil price environment (assumed oil price $28 per barrel in 2010). Reference Case 2 (the low energy growth scenario) indicates that a $2.50 price by 2010 would stimulate sufficient supply to sustain today's gas market share of limited energy growth outlook (assuming a constant oil price environment). Evaluation of supply potential beyond 2010 indicates that continuing technology gain can help minimize costs and perpetuate supply until 2020 at $2.50, and 2030 at $3.50.

- Annual oil and gas expenditures for the producing industry have averaged $35 to $40 billion (1990$) over the past few years. This is comparable to the level of expenditure in the mid-1970s and about half of the peak expenditure years in the early 1980s. For Reference Case 1, where domestic production increases to over 20 TCF by the year 2010, investment levels are projected to increase gradually over the next 10 years and average about $60 billion (1990$) annually during the 2000-2010 time period. Lesser increases are expected for Reference Case 2, which projects annual investments remaining below $50 billion (1990$) throughout the study period.

- A long history of intense and changing regulation, accentuated by public and private underestimates of supply potential, has worked to suppress demand and perpetuate the prevailing oversupply situation. The current contraction of producer activity is, in part, the delayed result of these forces rather than lack of drilling opportunity. Therefore, this trend is reversible if market signals so dictate. However, there may be some lag and some continued price volatility due to the lead time inherent in many investment decisions in all phases of the business.

- Contract diversity, driven by a customer-oriented attitude and supported by a regulatory climate that honors contract sanctity, can work to stabilize the market environment, encourage new supply, support demand growth, and ensure that the each participant attains the degree of reliability, security, and other services it desires. Risk management tools are also available to support all participants in managing exposure to competitive market uncertainty. Over time, such diversity and practices can work to better transmit market signals and reduce general price volatility.
- Technology advancement has proven to be a key factor in the historical growth of gas supply. Continued advancement of technology at similar rates is necessary to ensure that natural gas resources can be developed in a timely, cost-efficient manner. Private technology initiative must continue to play the lead role. An NPC survey of representative producer and service company research and development (R&D) spending indicates that technology effort remains strong despite reduced profits, declining drilling activity, and ongoing restructuring programs. Nevertheless, greater emphasis on cooperative programs is urged to ensure stability of technology effort, optimum performance, and effective technology transfer throughout industry. Federal funding, based on recognition that public interest would be served by a sustained, stable gas supply, is an appropriate supplement for programs that are not otherwise driven by proprietary advantage. Federal research funding for natural gas has been historically low relative to spending related to other fuels and should be reviewed in recognition of greater gas supply potential than previously assumed. Aspects that help reduce supply costs, including means to enhance environmental cost efficiency, merit greater consideration.
- The availability of natural gas, and the corresponding merits of its increased use as a clean fuel, are at risk from environmental restrictions on the supply side that limit access and raise costs without adequate balance of costs and benefits. A significant portion of the resource base is currently inaccessible due to leasing moratoria on the Outer Continental Shelf (OCS); is restricted in wilderness areas, marine sanctuaries, National Parks, and Fish and Wildlife Service lands; and is subject to other *de facto* administrative moratoria. The full potential of these areas will not be known until access is granted. Modeling results indicate that too stringent application of clean air, clean water, safe drinking water, hazardous waste, and other environmental laws without adequate regard to costs and benefits, including recognition of the downstream environmental benefits of natural gas, could potentially raise environmental compliance costs by $30 billion or more and reduce domestic supply 10 percent by 2010.
- The legislative and regulatory process should be reexamined and modified to bring more balance into the decision-making process. Industry must recognize and work to correct negative perceptions. It should develop innovative strategies to align its goals and preplan its projects to better recognize the public's environmental expectations. Industry and government need to enhance education programs and work to ensure that factual information is available and communicated to help bring a better balance to environmental decision making.

RESOURCE BASE

Lower-48 Resource Base

Historical Perspective

For many years, it was popular practice to view the U.S. supply base by looking primarily at proved reserves. In large part, this attitude grew directly out of the pipeline certification process of the Federal Power Commission. To obtain a certificate, a showing of market demand and gas supply was required. The supply requirements typically involved the identification of proved reserves to be dedicated to the project for the lifetime of the facility. Institutions providing capital relied on these dedicated reserves and the certificates for the viability of the proposed project. This process, in conjunction with low gas prices,

helped support a rapid expansion of demand but provided little incentive for adding new proved reserves as the formerly vast reserve base reached its peak. By the late 1960s, proved reserves were declining. As can be seen in Figure 3-1, through most of the 1970s the proved reserve base progressively declined as controlled prices remained well below replacement needs. By the mid-1970s the ratio of proved reserves to annual production had dropped to ten years from a peak of 38 years in 1946. Even though the drop was largely a logical correction to a more economically sustainable level, there was fear it would keep dropping.

This has not turned out to be the case. In fact, the 10 year reserves-to-production ratio for the lower-48 states has remained at about that level for the last 15 years. As can be seen in Figure 3-2, reserves have remained relatively constant even though substantial additional gas has been produced in the meantime. Obviously, there is additional resource potential to replace the proved reserves as they are used. In simple terms, proved reserves represent and should be perceived as an *inventory* rather than an ultimate capability. Producers will invest in exploration and development to add to proved reserves as there is need and incentive.

The NPC Resource Base Estimate

It is critical to change the focus from proved reserves to recoverable resources. Much work has been done and published in this regard by various organizations and institutions in the past. Accordingly, several NPC Source and Supply subgroups were formed to draw from this expertise as well as to undertake further original work as deemed necessary. Special focus was given to reserve appreciation, tight sands, and technology advancement. The NPC natural gas resource estimate of 1,295 TCF is the result of that extensive effort. It represents current proved reserves plus assessed technically recoverable resources under technology projected to be applicable by 2010.

This estimate, shown by resource category in Table 3-1, constitutes the consensus opinion. Recognizing that neither today's gas price nor today's technology should limit projection of the supply base available to meet future needs, no explicit economic or price assumptions were set as criteria; however, subjective judgment was used to exclude poorly defined and diffuse portions of the in-place resource potential and to establish reasonable technology trends and recovery factors for the remaining areas. For example, poorly defined nonconventional potential and exotic possibilities such as hydrates were excluded. Recovery factors for both conventional and nonconventional gas were established, anticipating technology advancement over the next 20 years consistent with past experience. The conceptual interrelationship between reserves, resources, economics, and technology is shown graphically in Figure 3-3.

TABLE 3-1

NATURAL GAS RESOURCE BASE FOR THE LOWER-48 STATES (Trillion Cubic Feet)

Proved Reserves	**160**
Conventional Resources	
Reserve Appreciation	203
New Fields	413
Subtotal	**616**
Nonconventional Resources	
Coalbed Methane	98
Shales	57
Tight Sands	349
Other	15
Subtotal	**519**
Total Resources	**1,295***

*Technically recoverable resource base as of January 1, 1991, assuming that current access moratoria expire as scheduled and incorporating technology advancement through 2010. Assuming various price levels with current and advanced technology, yields the following total resource estimates:

	Recoverable Resource Base (TCF)	
Price (1990$)	1990 Technology	2010 Technology
Unspecified	1,065	1,295
$3.50/MMBTU	600	825
$2.50/MMBTU	400	600

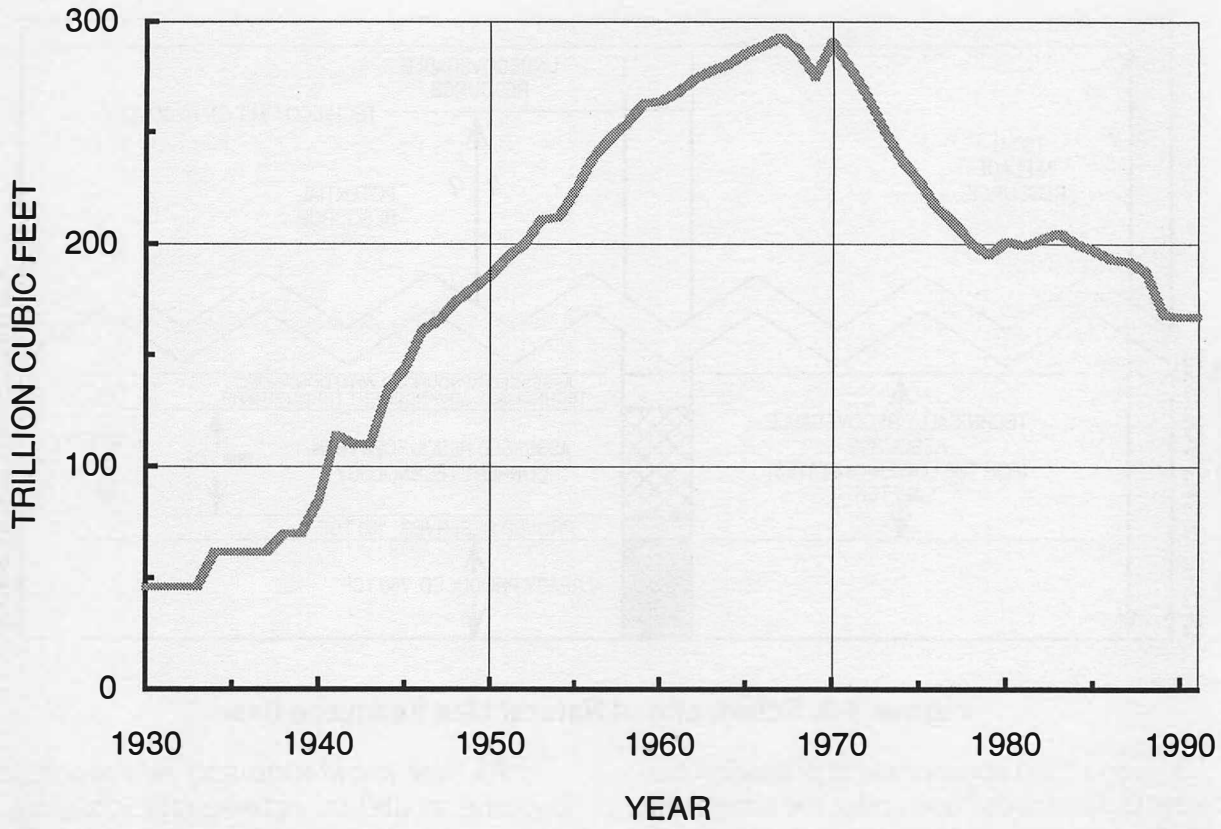


Figure 3-1. U.S. Natural Gas Proved Reserves.

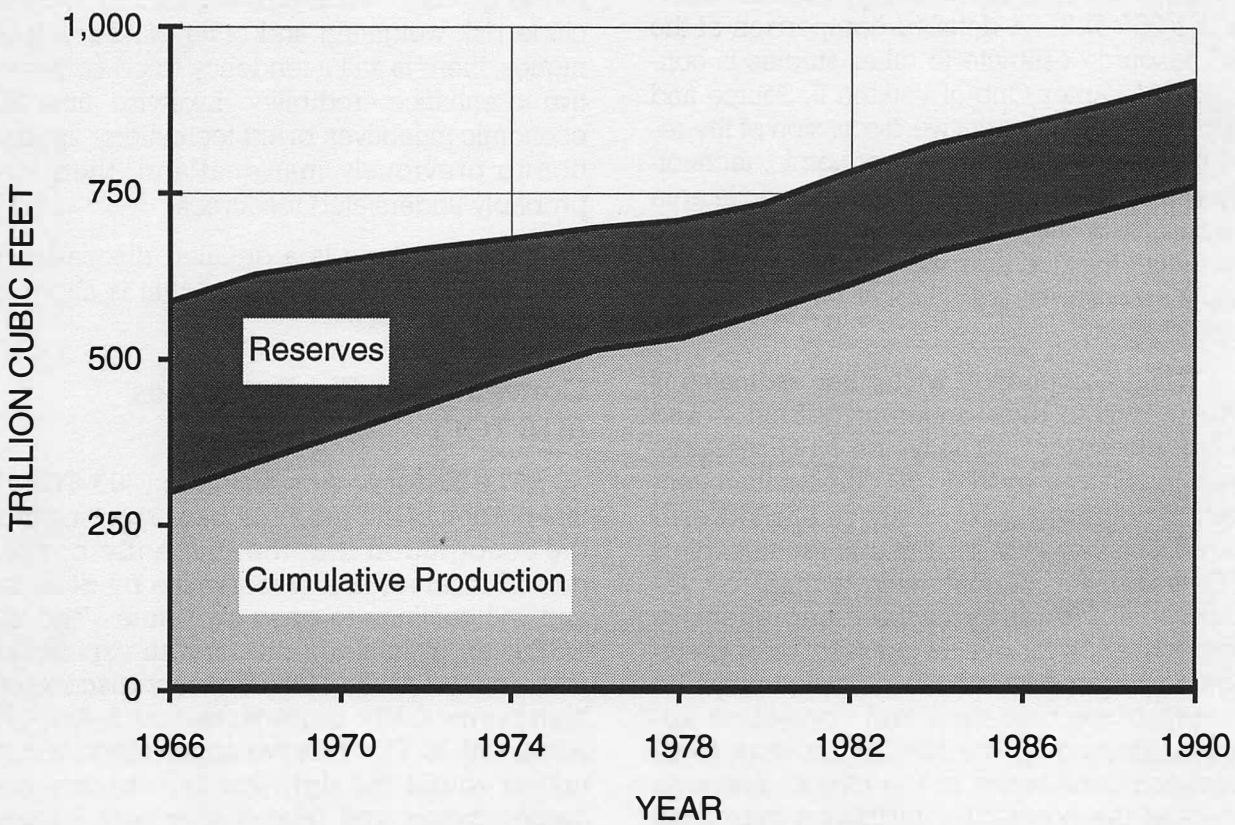


Figure 3-2. U.S. Reserve History.

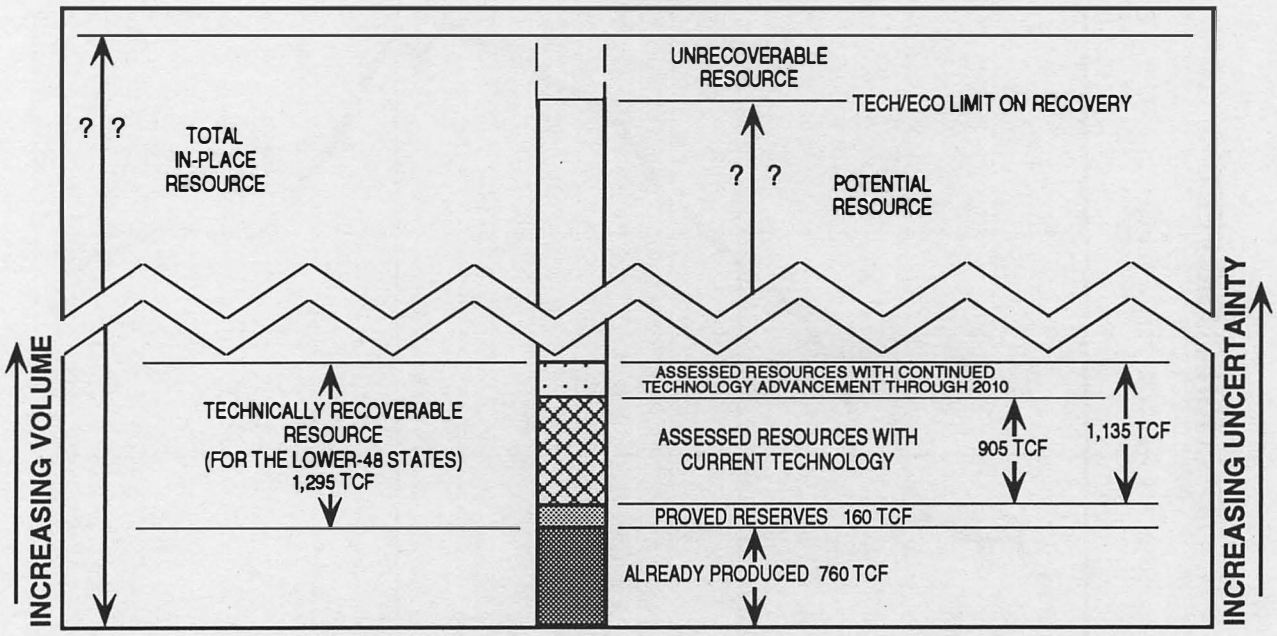


Figure 3-3. Schematic of Natural Gas Resource Base.

It was judged appropriate to primarily characterize the resource base under the assumption of 2010 technology to best recognize that technology is a continuing process and thus the recoverable resource base is dynamic and growing. The comparable estimate assuming there is no further advance in technology from 1990 levels is 1,065 TCF. A detailed comparison of the NPC resource estimate to other studies is contained in Chapter One of Volume II, Source and Supply. A more quantitative discussion of the resource base under specific economic, technology, and access assumptions is discussed later in this summary after establishing the economic and technology criteria used in developing the supply assessment (see Supply Curves section of this chapter).

While comparison with other estimates is difficult due to differences in definition and methodology, directionally, the NPC resource estimate is larger by 10 to 20 percent than generally recognized, previously published estimates. This is partly attributable to the explicit NPC recognition of continuing technology advancement and partly to the comprehensive approach taken for evaluating reserve appreciation and tight sands. More importantly, the breadth of participation and consensus approach adopted for the NPC study work gives increased confidence in the overall resource base and the potential contribution from each resource category.

As new knowledge and new technology become available, subsequent forecasts by others would be expected to increase as well. There is uncertainty for any resource base estimate, in part because of the inherent uncertainty in defining any opportunity that remains in the ground. Although estimating tools include risk weighting and other statistical techniques, there is still a tendency to be conservative to enhance credibility. Likewise, time and economic incentives bring technology application to previously marginal and, therefore, probably understated resources.

The following is a detailed discussion of the 1,295 TCF resource base that is shown in Table 3-1.

Conventional Gas Resources (616 TCF)

The Reserve Appreciation (203 TCF) is that portion of the resource base resulting from the recognition that the currently booked proved reserves are conservative by definition and will continue to grow over time. The 203 TCF is an estimate of that growth expectation from today forward for currently discovered, high permeability conventional gas fields. (An additional 33 TCF reserve appreciation is contained within the tight sands resource discussed below and relates to growth for currently producing low permeability fields.) This

resource is incremental gas likely to be added over time in fields that already have produced 760 TCF and contain proved reserves of 160 TCF. Such appreciation occurs as a result of reserve additions from field extensions, new reservoirs, and revisions due to infill drilling, improved technology, enhanced recovery, well workovers, and recompletions. Increasingly sophisticated technologies, such as 3-D seismic, cased-hole well logging, and horizontal drilling, help to make such reserve growth a reality. Historical evidence shows that fields more than 50 years old are still showing significant additions.

NPC analytical work on reserves appreciation involved statistical analysis of a large data base containing reserve estimates for the 1966-1989 period. The results of the analysis showed that reserve additions can be correlated to both time (maturity of fields) and level of activity (drilling). Reserve appreciation statistical results were confirmed by a confidential survey of individual company experience regarding reserves appreciation for a number of specific fields.

The New Fields category (413 TCF) applies to gas yet to be discovered. Since wildcat exploration will be required to find this gas, it is largely based on risked assessments attributing geologic similarities from known areas. Much of it will be at greater depth and in deeper water than historically developed, or in smaller fields if found in more mature areas.

Nonconventional Resources (519 TCF)

For convenience shale gas, coalbed methane, and tight gas are classified together as "nonconventional" gas. Although this is somewhat of a misnomer, the term nonconventional is used because each of these is in a relatively early stage of technical development. Figure 3-4 shows the most active basins and those with the most significant potential.

For gas from shale (57 TCF), coalbed methane (98 TCF), and tight sands (349 TCF), both public and company sourced evaluations were used to establish likely recoverable estimates. For tight sands, consultants were also used to aggregate extensive data obtained

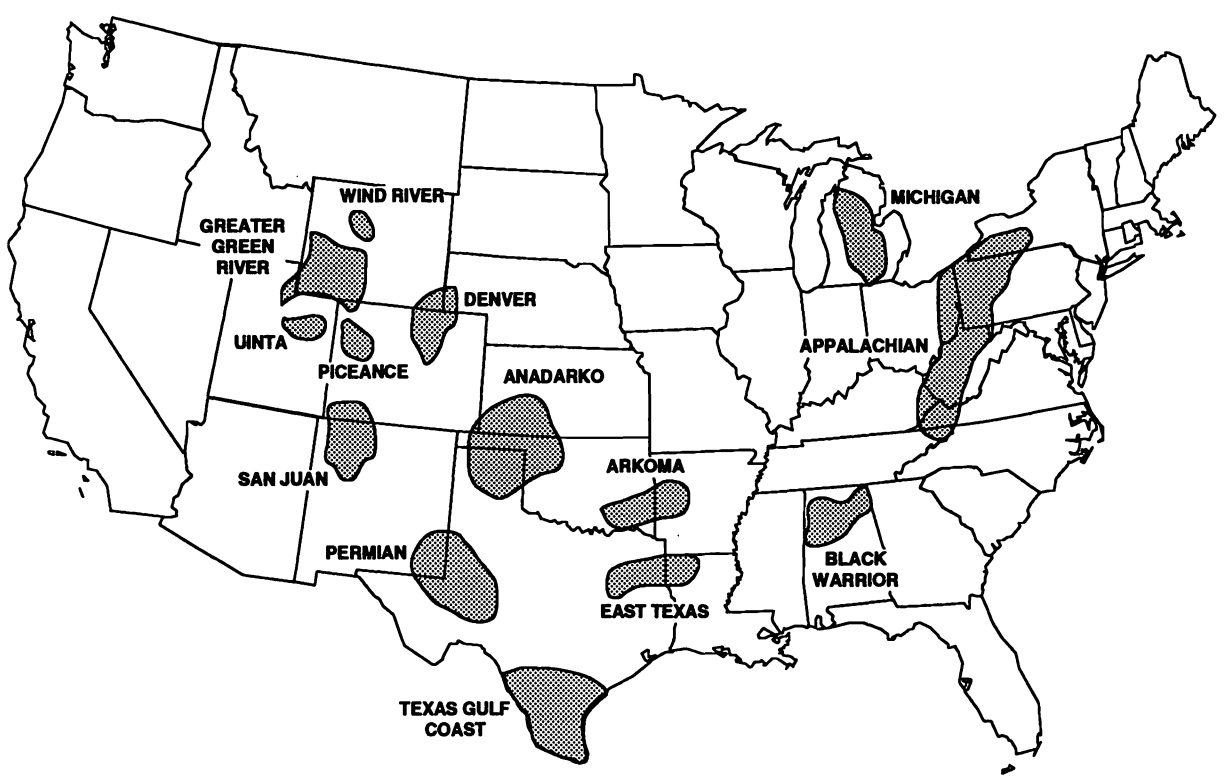


Figure 3-4. Location of Principal Nonconventional Gas Basins.

from a confidential survey of current operators and assist in a statistical analysis of historical production data.

It should be recognized that, although the potential tight sands resource base is quite large, the NPC has evaluated in detail only that portion for which sufficient data exist to adequately characterize potential. For example, the U.S. Geological Survey (USGS) has estimated that overpressured tight formations in the Greater Green River Basin alone contain over 5,000 TCF of gas in place. The economic development of most of this and similar in-place potential elsewhere is highly speculative at this time and is expected to require technology or cost/price improvements beyond those considered reasonable in this study. Therefore, only those portions of formations that are currently under development or are expected to be significantly developed during the study period (1990-2010) are included in the 349 TCF assessment for tight gas.

Import/Alaskan Resources

Canadian resource potential has also been examined using evaluation techniques similar to those used for the United States. The NPC estimate of 740 TCF, as shown in Table 3-2, is larger than generally acknowledged in reports published by others, especially in the relatively accessible western basin (excluding the 317 TCF Frontier). It includes significant coalbed methane (129 TCF) and tight sands (89 TCF). To eventually be competitive, natural gas resources in the frontier areas face the extra transportation burden imposed by their remote location.

Alaska has a considerable gas resource base (180 TCF), but it too suffers the burden of remote location relative to lower-48 markets. Mexico (252 TCF) is currently a net importer of natural gas, but this is expected to reverse over time.

Several countries interested in exporting LNG to the United States also have vast resources in comparison to their indigenous demand potential. These include Nigeria, Venezuela, Algeria, and Norway.

Combined Resource Potential

The cumulative potential of all these sources is shown in Figure 3-5. Obviously not all of these 2,500 TCF in resources are ultimately destined for the United States. However, the large size of the U.S. market compared to other North American markets, and the strides taken in recent years to implement free-trade principles, make the conclusion of a vast and diverse resource base self-evident. **Therefore, from a resource standpoint, natural gas deserves the same perception as has been long held for coal—namely, that the resource, itself, is not a limiting factor.** While this perception has already taken hold in some quarters, the NPC recommends that it be brought forth for more general adoption both in the marketplace and as a criteria for governmental policy.

TABLE 3-2

CANADA
NATURAL GAS RESOURCE BASE
(Trillion Cubic Feet)

Proved Reserves	**72**
Conventional Resources	
Reserve Appreciation	24
New Fields	109
Frontier	317
Subtotal	**450**
Nonconventional Resources	
Coalbed Methane	129
Tight Gas	89
Subtotal	**218**
Total Resources	**740**

Basis — Technically recoverable resources incorporating technology advancement through 2010.

SUPPLY POTENTIAL (ECONOMIC AVAILABILITY)

Of equal importance to an adequate resource base is the capability to translate it into timely and competitive supply. Clearly, the natural gas industry is demonstrating such a capability, as evidenced by the level of deliverability that has been maintained for the last decade in the face of declining prices and soft demand.

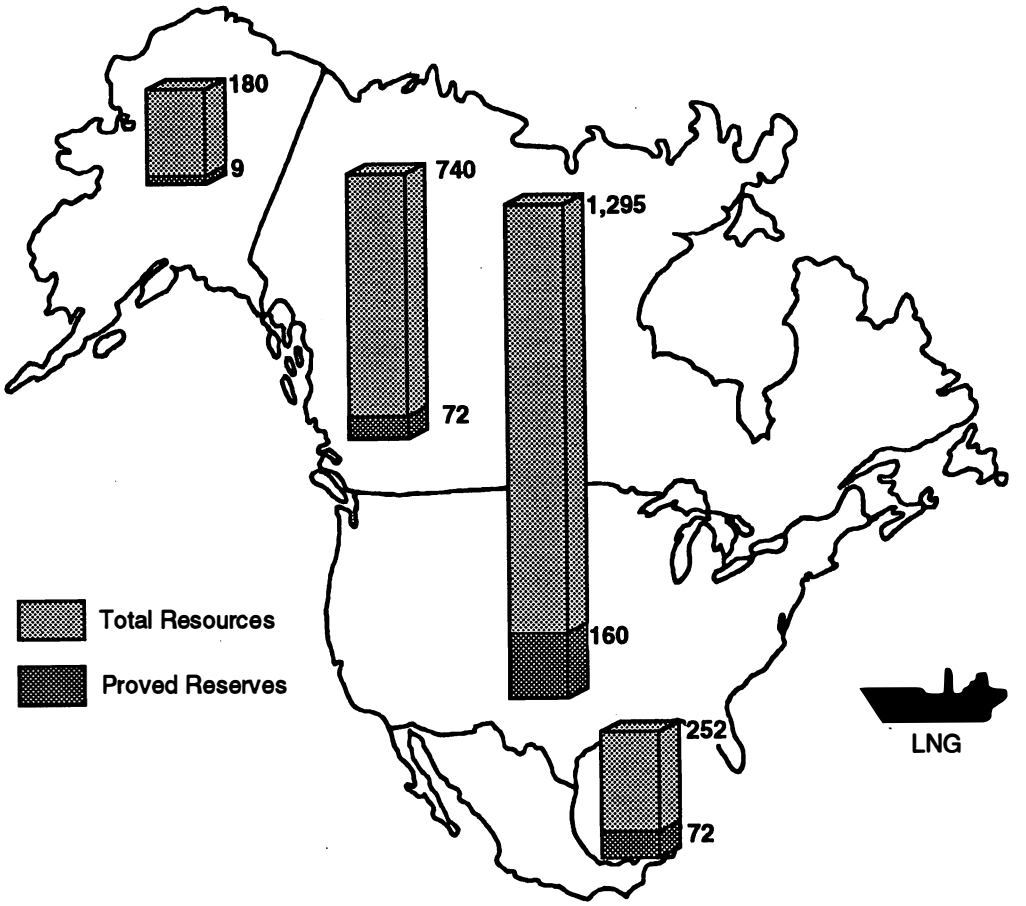


Figure 3-5. Combined Resource Potential.
(Trillion Cubic Feet)

Nevertheless, shortages of the early 1970s leave concern as to whether supply can and will be sustained. Recent industry steps to downsize domestic exploration and development activities add to the concern. The historical business and regulatory factors influencing these cycles as well as the physical potential to add new capacity in the future have been examined:

- Natural gas supply can be made competitively available to meet foreseeable demand growth if proper market signals, technology advancement, and environmental management practices are forthcoming.
- Market practices and government policy appear to be moving appropriately in the direction necessary to ensure that supply growth will occur as needed. The recommendations contained in this study that encourage further progress toward a customer-oriented, free market are critical to maintaining momentum in that direction.

Key Supply Parameters

Concurrent with evaluation of the resource base itself, various subgroups assessed finding, drilling, and development costs; technology contribution; environmental trends; and import potential to establish a realistic basis for supply prediction. Confidence in study results was enhanced by integrating assessment of supply dynamics with assessment of each related portion of the resource base itself. The approach and results of this effort are summarized below and discussed in depth in Volume II, Source and Supply.

Conventional Gas

Gas from already proved reserves and reserve appreciation should be relatively economic to develop, since both are closely associated with discovered reservoirs and existing infrastructure. An indication of reserve growth potential and its near term significance to supply

availability is apparent from reserve addition statistics of the past ten years. As shown in Figure 3-6, new fields contribute a relatively modest portion of the total proved reserve additions added each year. Reserve growth (new reservoirs, extensions, and net positive revisions) make up the rest.

The chart also demonstrates an exceptional trend for reserve revisions during the last five years. Despite relatively low gas prices compared to the early 1980s, net revisions jumped to an annual average of positive 6.5 TCF in the late 1980s from an historical average of positive 1.5 TCF for the prior 10 years. (Contrary to earlier expectations, newly released EIA data for 1991 show a continuation of this 6.5 TCF trend.) Well recompletion data and Natural Gas Supply Association survey estimates of deliverability support the assumption that such revisions are real. Apparently, producers reacted to difficult times by focusing management attention and technological innovation on maximizing low cost gas recovery in fields already owned. Undoubtedly these results not only demonstrate the resourcefulness of the industry but help explain the persistence of the long-standing "gas bubble."

Substantial new field discovery potential remains in the United States as well as in Canada. Much of the potential is onshore and can be developed with limited lead time once discovery occurs. Directionally, supply from new fields, especially in the United States, will be more expensive than past production, as it will increasingly come from smaller and deeper fields, as well as from fields in deeper waters offshore. Continuing advances in exploration and development technology and efficiency will help ensure that such supply can be produced competitively. Access, especially to the offshore potential, and reasonable environmental regulations are essential as well.

Nonconventional Gas

Production of coalbed methane has risen at an impressive pace in the last few years in part due to tax incentives, but also due to rapidly advancing technology. Similar potential applies to tight sands. A key finding for tight sands is that the cost of production will be much lower than indicated by a 1980 NPC study, *Unconventional Gas Sources*. The 1980 work anticipated massive hydraulic fracturing with great fracture lengths. While fracture lengths have not increased as much as expected, this has been more than offset by new stimulation fluids, better fracture techniques, cavity completion techniques, and significant advances in ability to detect, interpret, and selectively develop potentially productive intervals.

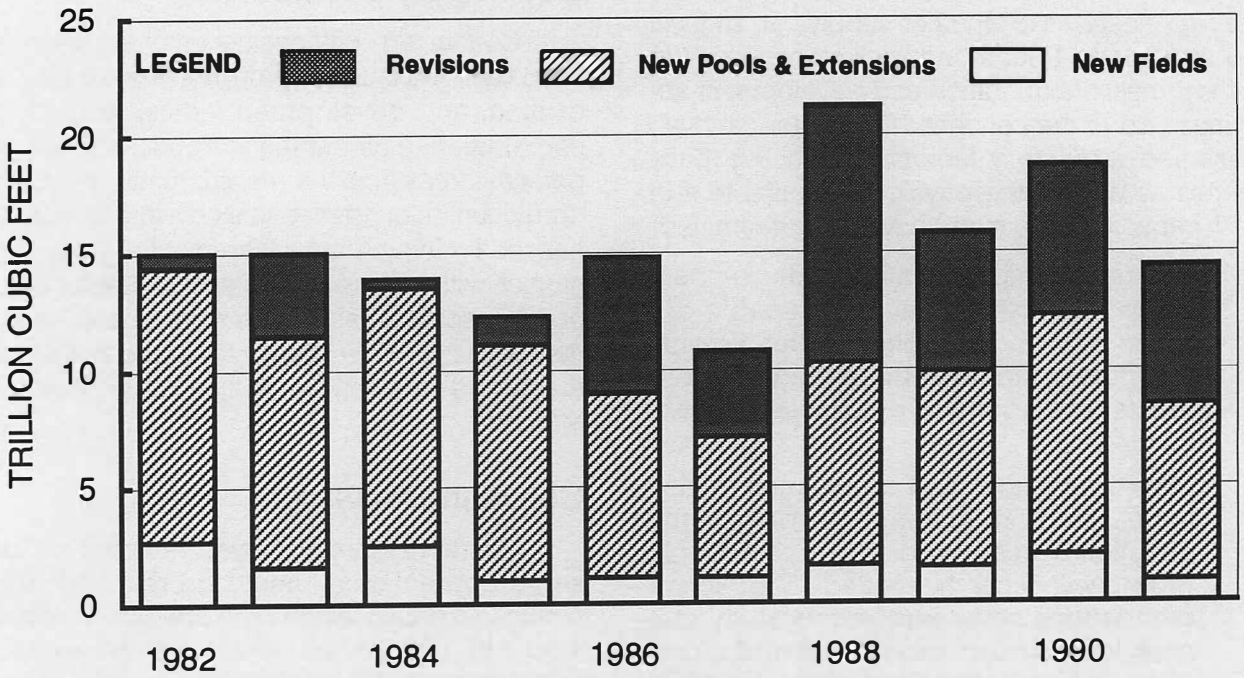


Figure 3-6. U.S. Lower-48 Historical Reserve Additions.

Technology

Early in the study, it was unanimously agreed that technology could be the most important factor in the future of natural gas supply. A qualitative survey was undertaken by participating companies to assess technology contribution over the last 20 years. It found uniform concurrence that the technology impact has been high in all of the over 50 categories examined. Most respondents not only expect further technological gain, but that the pace will actually accelerate. Substantial anecdotal evidence exists to support this conclusion as do the specific technology discussion papers available in the appendices of this report.

Areas perceived as especially important for technology advancement in coming years include improved exploration tools to enhance success as wildcat opportunities mature, further advances in reservoir stimulation, improved means to detect uncontacted resources in developed fields, and better means to cost-effectively minimize environmental impact.

To calibrate the qualitative survey trends, a consultant undertook a statistical analysis of historical drilling costs, for which detailed data are more available than for other cost categories. After sorting between technology and other factors such as inflation and rig availability, the correlation showed an underlying technology-based cost savings trend of 3 percent/year on drilling costs for the 1970-1989 study period. Confirmation came from earlier NPC work. A 1967 study of the 1950-1965 period also showed a 3 percent/year trend for drilling costs using an entirely different methodology.

Environmental Regulation

Compliance with environmental regulations continues to be an ever increasing component of the cost of producing natural gas. During the 1970s and 1980s, compliance costs grew an average 4 percent/year, adjusted for inflation. The potential for a continuation of this trend, combined with growing restrictions for both onshore and offshore access to new exploration opportunities, led the NPC to take a detailed look at the implications of potential new restrictions on exploration and production operations. Building on earlier work done by organizations such as the API, a range of possible applications was established for such legislation as the Resource Conservation and Recovery Act (RCRA), the Clean Water Act (CWA), the Safe Drinking Water Act (SDWA), and the Clean Air Act (CAA).

The general conclusion, and the assumed basis of the Reference Cases reported in this study, is that reasonable application of new rules using a balanced cost/benefit approach would continue to raise compliance costs at a pace somewhat below the historical rate of increase but should not have an overwhelmingly adverse effect upon overall gas-producing costs—aggregating to about 10 percent above today's already carefully controlled and monitored operations.

However, as will be discussed in Chapter Seven, Environment, and elaborated on in Volume II, there is substantial risk that such balance will not prevail. Access restrictions and extreme regulation could significantly constrain supply and raise costs at an accelerating pace well above the historical rate of increase unless today's process is modified so as to better balance environmental risk and other national needs. For natural gas this includes recognition of its "downstream" environmental attractiveness as a clean fuel.

Modeling Approach

As the second step in evaluating supply potential, the study adopted and modified an already highly sophisticated computer simulation model known as the Hydrocarbon Supply Model. Utilization of the modeling approach allows determination of natural gas price trends required over time to sustain supply and meet demand growth opportunity in competition with other user alternatives such as coal and fuel oil. It allows for recognition of time-dependent factors such as technology advancement, reserve appreciation, and access restrictions.

Given the complexity of the nation's natural gas business, its diverse resource base, and the number of factors that can influence conversion to deliverable supply, the two Reference Cases were developed to provide a benchmark for assessing supply potential in the context of expected market opportunities.

Several assumptions that are critical to the supply results were made for both Cases:

- Supply will be driven by market need. The excess of supply prevalent for the last few years is believed to be the result of market transition. It is assumed that it will dissipate with time in response to market signals. For the Reference Cases, it is assumed that producers will have "perfect foresight" of market opportunities and price trends when adding new reserves and delivery capacity as currently available supply undergoes economic depletion.
- It is assumed the current supply-industry restructuring will self-correct when necessary. There will be no regulatory, contract practice, transportation, or storage limitations that distort market signals from reaching the supply community in a timely manner.
- Industry profitability and reinvestment ratios will vary year to year and individually, as circumstances dictate, but it was assumed that they will generally be in line with historical levels (i.e., averaging approximately 5 percent real annual rate of return after tax and 70 percent expenditure/income).
- There will not be significant tax distortions or free-trade restrictions that bias natural gas supply type or source—either national or international in nature. Specifically, it is assumed that Section 29 tax credits are not extended beyond 1992.
- There will be no further exploration or development access restrictions than now applicable under existing laws and moratoria. It is assumed that existing offshore (OCS) moratoria are not renewed at the end of their current terms. Estimated first exploration opportunity after assumed expiration of the moratorium is shown on Table 3-3.
- Technology advancement will continue at a pace consistent with survey indications. Specifically, it is anticipated that drilling costs will benefit from a technological improvement estimated at 4 percent/year. Resource recovery will increase approximately 0.5 percent/year for conventional gas and 2 percent/year for nonconventional gas.

TABLE 3-3

OCS MORATORIUM AREAS ESTIMATED FIRST EXPLORATION ACCESS

Eastern Gulf	1997
North Atlantic	2010
Mid-Atlantic	2002
Florida Straits	2015
California	2005
Washington/Oregon	2010

These assumptions are both achievable and appropriate for the purpose of characterizing what can be accomplished consistent with the NPC vision of sound government policy and a healthy market environment.

In addition to the judgments listed above, the model's methodology and numerous explicit assumptions were closely examined, including: resource definition by field size, depth, and basin within both the United States and Canada; onshore and offshore drilling and development cost parameters; new field finding rates; LNG development, shipping, and terminal costs and capacities; etc.

The judgments and explicit assumptions used for modeling analysis are subject to external influence and technical uncertainties that will vary from year to year as events unfold. Therefore, the Reference Cases and sensitivities described below are intended to be instructive trend indicators rather than forecasts. Neither Reference Case nor any sensitivity is considered more or less probable than any other.

Supply Implications of Reference Case 1 (Moderate Energy Growth Scenario, 1991-2010)

Reference Case 1 represents the stronger demand outlook of the two Reference Cases chosen. Although it does not represent maximum gas demand (or supply) potential, it does provide a sound basis for defining supply capability within a realistic framework of a growing market. Directionally, it demonstrates that natural gas supply can be made competitively available to meet growing demand opportunity

through 2010 (the last year for which detailed demand analyses were conducted.)

Specific model results and trend indicators are summarized in Table 3-4. Under this scenario, gas supply increases by 25 percent from 19.3 TCF in 1991 to 24.3 TCF in 2010 (equivalent to 25 QBTU). Figure 3-7 shows the supply trend and supply mix by year. (For convenience of comparison, Reference Case 2 supply is shown in Figure 3-8).

For Case 1, in response to competitive market requirements, domestic production rises 18 percent from 17.5 TCF in 1991 to 20.7 TCF by 2010. By 2010, 29 percent of domestic supply comes from nonconventional supplies as opposed to 12 percent in 1991. Imports double to 3.6 TCF/year by 2010 or 15 percent of total supply. Most of the import gain is expected to be Canadian gas from traditional western producing regions. It is not expected that North Slope Alaskan or Canadian frontier gas (MacKenzie Delta) will be competitive within the 2010 time frame. LNG imports rise to 0.3 TCF/year, utilizing less than one half of existing capacity at the four available terminals.

Under Case 1, utilization of domestic deliverability increases sharply in the next few years. Utilization has stayed in the low 80 percents for the last five years but approaches 94 percent by 1995, anticipating that recent cutbacks in activity continue for the interim. Afterwards, it would likely stay near year-round maximum utilization, estimated to be 96 percent.

The model results indicate that gas will remain competitive in the market under the demand assumptions of this scenario, even though the average wellhead price necessary to encourage adequate supply increases over

TABLE 3-4

REFERENCE CASE 1 SUPPLY SUMMARY
MODERATE ENERGY GROWTH SCENARIO

	1991	1995	2000	2005	2010
Supply, TCF/year					
Domestic	17.5	17.9	18.6	20.1	20.7
Imports	1.8	2.5	3.1	3.0	3.6
Total	19.3	20.4	21.5	23.1	24.3
Deliverability					
Utilization, %	83	94	96	94	95
Wellhead Price					
Texas Gulf Spot, 1990$/MMBTU	1.27	1.98	2.88	2.76	3.47
Gas to Oil, %	40	60	79	64	72
Well Completions					
Gas	9,800	9,800	12,500	14,400	18,400
Proved Reserves, TCF					
Lower-48	156	143	137	148	153
Canadian	70	64	66	71	77
Memo—Oil Price					
1990$/Barrel	18.38	19.01	21.10	25.14	27.85
1990$/MMBTU	3.16	3.27	3.63	4.34	4.80

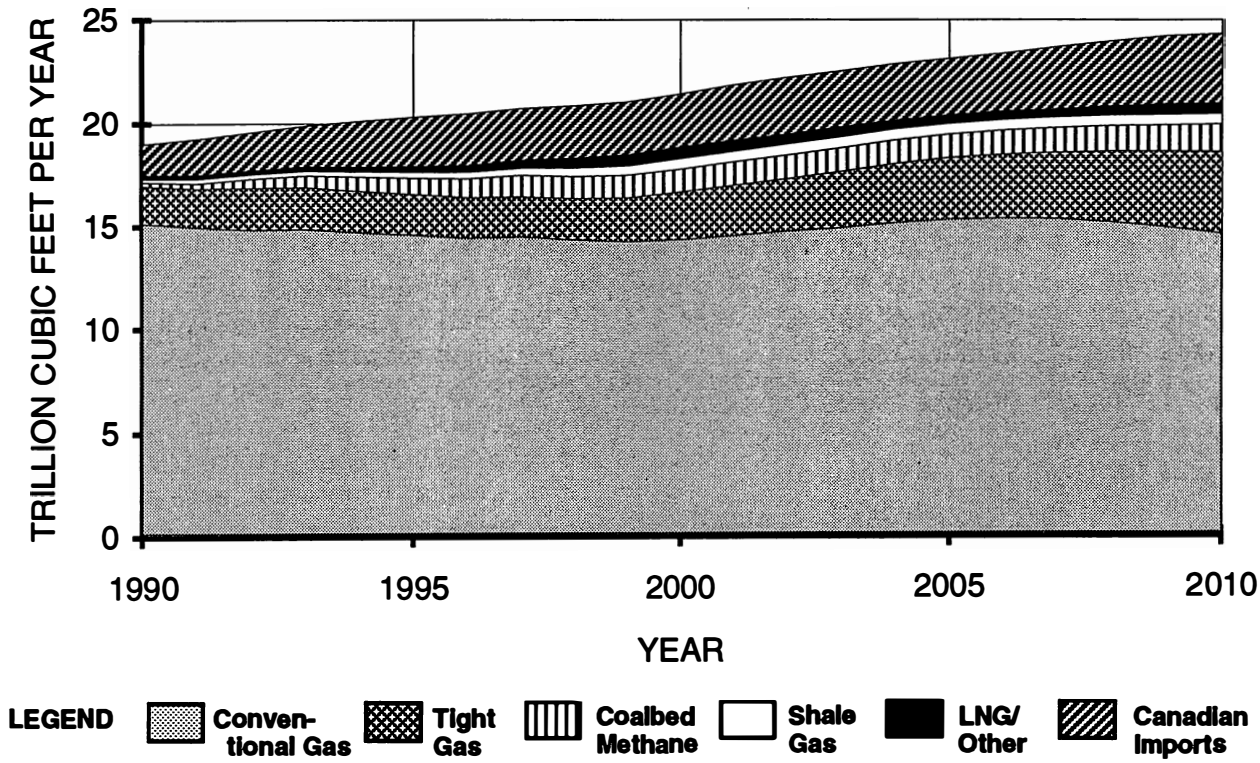


Figure 3-7. U.S. Lower-48 Gas Supply—Reference Case 1.

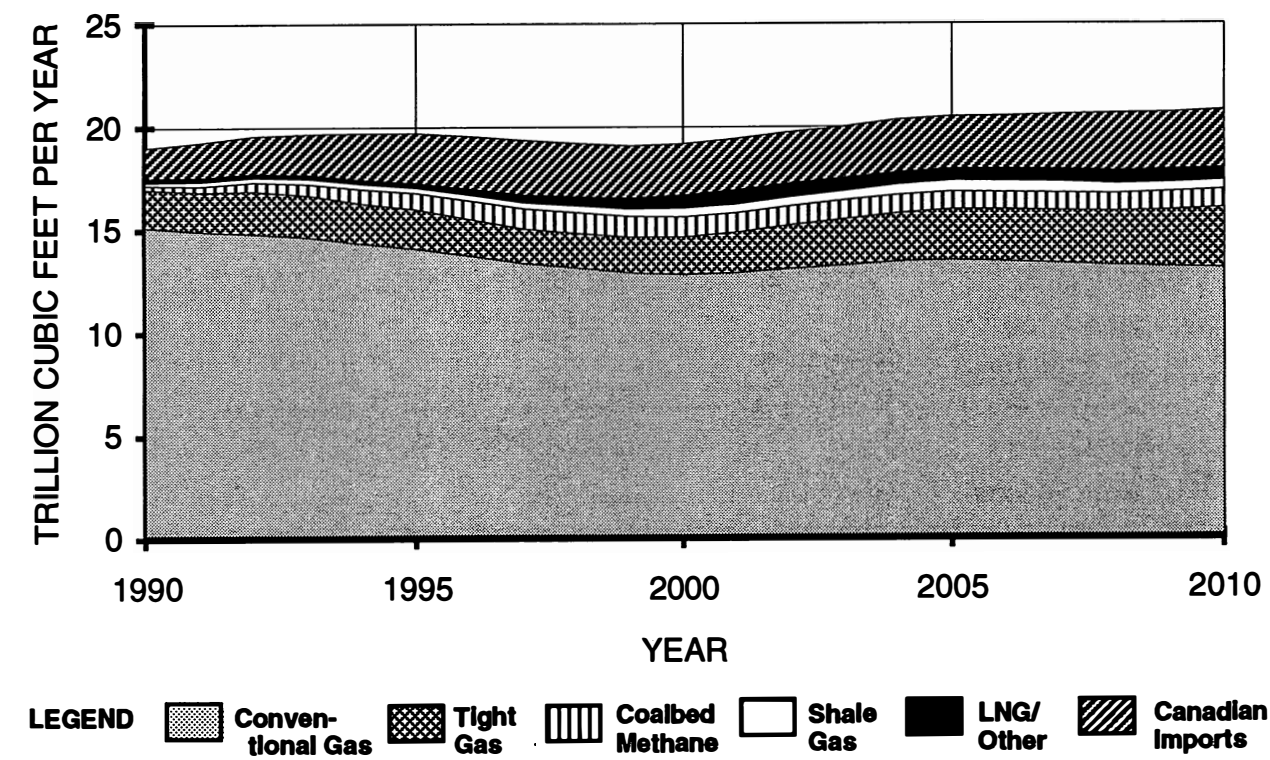


Figure 3-8. U.S. Lower-48 Gas Supply—Reference Case 2.

the 20-year study period (see Figure 3-9). Model results show a steady increase in price until the turn of the century, driven on the supply side by increasingly expensive incremental supply from conventional sources. This can be seen from the drilling requirements shown in Figure 3-10. Drilling for conventional gas doubles during the next ten years followed by a rapid buildup for tight sands drilling thereafter. Once full deliverability utilization is reached, at the turn of the century, it plateaus at about $2.80/MMBTU ($1990) for a decade before rising to about $3.50/MMBTU in 2010.

Compared to crude oil on a BTU equivalency basis, the gas wellhead price increases from about 42 percent today to about 72 percent by 2010. This is a substantial increase at the wellhead, but somewhat offset at the burnertip by increased efficiency of transportation due to higher throughputs. Demand-side factors and burnertip price comparisons that support this competitive supply/demand balance are discussed in Chapter Four, Market Opportunities, and in Volume III, Demand and Distribution. Generally, burnertip prices remain competitive due to rising alternative fuel costs, increasingly stringent environmental standards that natural gas more easily meets, and the relatively low capital requirements and high efficiency of natural gas facilities.

Figure 3-12 adds a 30-year historical perspective. Neither the demand nor price exceed historical peaks. Indeed, the historical peaks and valleys generated by misregulation stand out as an anomaly.

Supply Implications of Reference Case 2 (Low Energy Growth Scenario, 1991-2010)

Reference Case 2 represents a relatively weak demand outlook with the challenge for natural gas compounded by the assumption that oil prices remain near today's level through the next 20 years. Results are summarized in Table 3-5 and Figures 3-8, 3-9, and 3-11. Figure 3-13 adds a 30-year historical perspective to the Case 2 results.

Modeling results indicate natural gas supply can competitively respond with total supply increasing slightly from 19.3 TCF/year in 1991 to 20.8 TCF/year in 2010. Domestic production would be sustained at close to current levels. Imports, primarily from Canada, would increase about 75 percent to 3.1 TCF/year. Lower producer activity in proportion to perceived lower demand and lower competitive crude oil pricing, would yield a deliverability utilization similar to Case 1—namely, an increase to essentially full utilization by the turn of the century. Wellhead price by 2010 would be approximately 0.75 $/MMBTU lower than Case 1.

The possibility that overall domestic production would stay essentially constant results in substantially different service industry needs for the next ten years. Drilling stays essentially constant through the turn of the century under Case 2, compared to a doubling under Case 1. Thereafter, service industry needs would still increase due to smaller field size and increased utilization of nonconventional gas resources made economic by the combined effect of technology advance and higher wellhead prices than today.

Long-Term Supply Sustainability (1991-2030)

The modeling approach was also used to assess the sustainability of competitive gas supply for the longer term beyond 2010. Many current natural gas users (particularly residential and commercial with limited fuel switching capability) and potential new customers (particularly capital intensive electric utility and industrial) need assurance of supply beyond the 20-year study period. While such security may be individually attainable through term contracting, it is appropriate to look at the underlying aggregate long-term gas supply potential for additional comfort.

For the purpose of this evaluation, gas demand and oil and natural gas prices were assumed to rise in a manner similar to Case 1. With these benchmarks, gas supply potential was assessed at various maximum price levels—specifically $1.50, $2.50, $3.50, and $4.50/MMBTU (1990$). The resulting supply capability is shown in Figure 3-14.

Results suggest that gas supply cannot be sustained even for the near term at $1.50/MMBTU but is readily sustainable well beyond 2010 within the range of $2.50 to $3.50/MMBTU (1990$). Compared to the oil

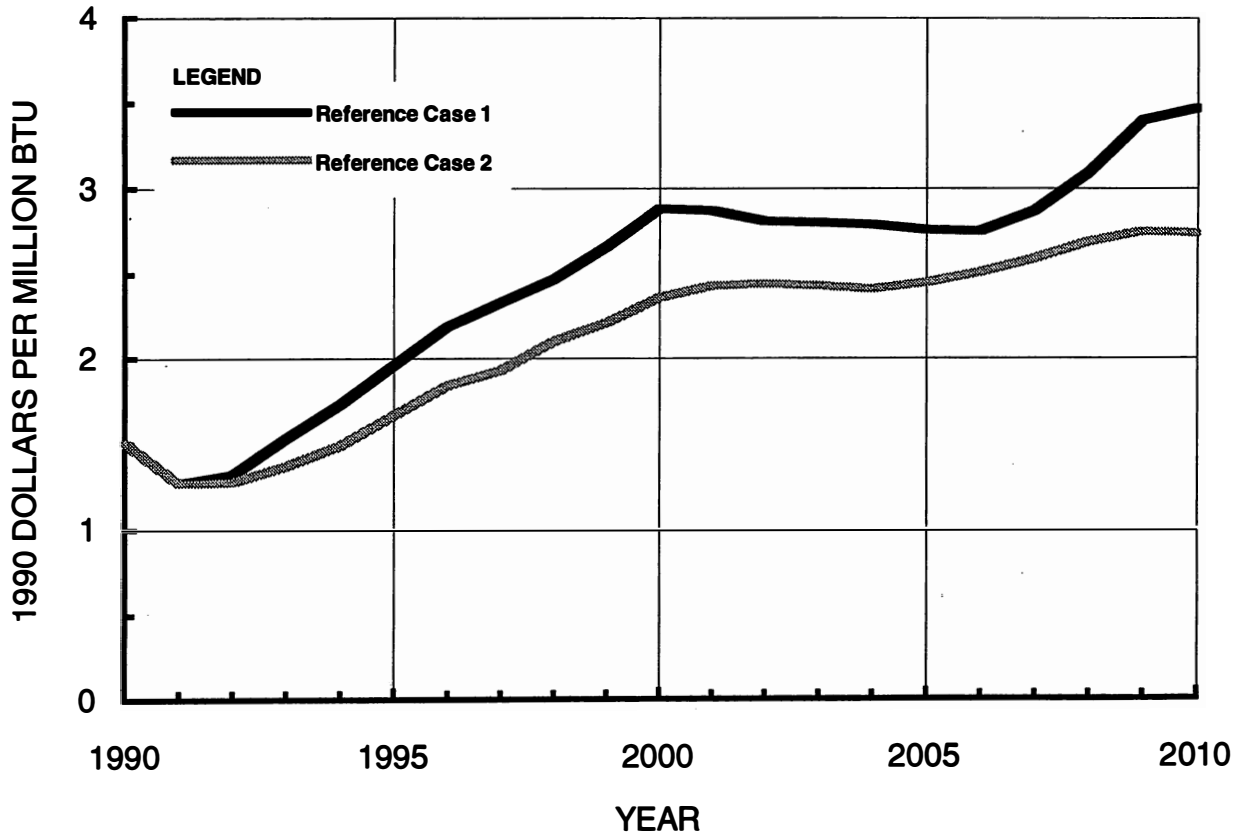


Figure 3-9. Texas Gulf Spot Wellhead Gas Price.

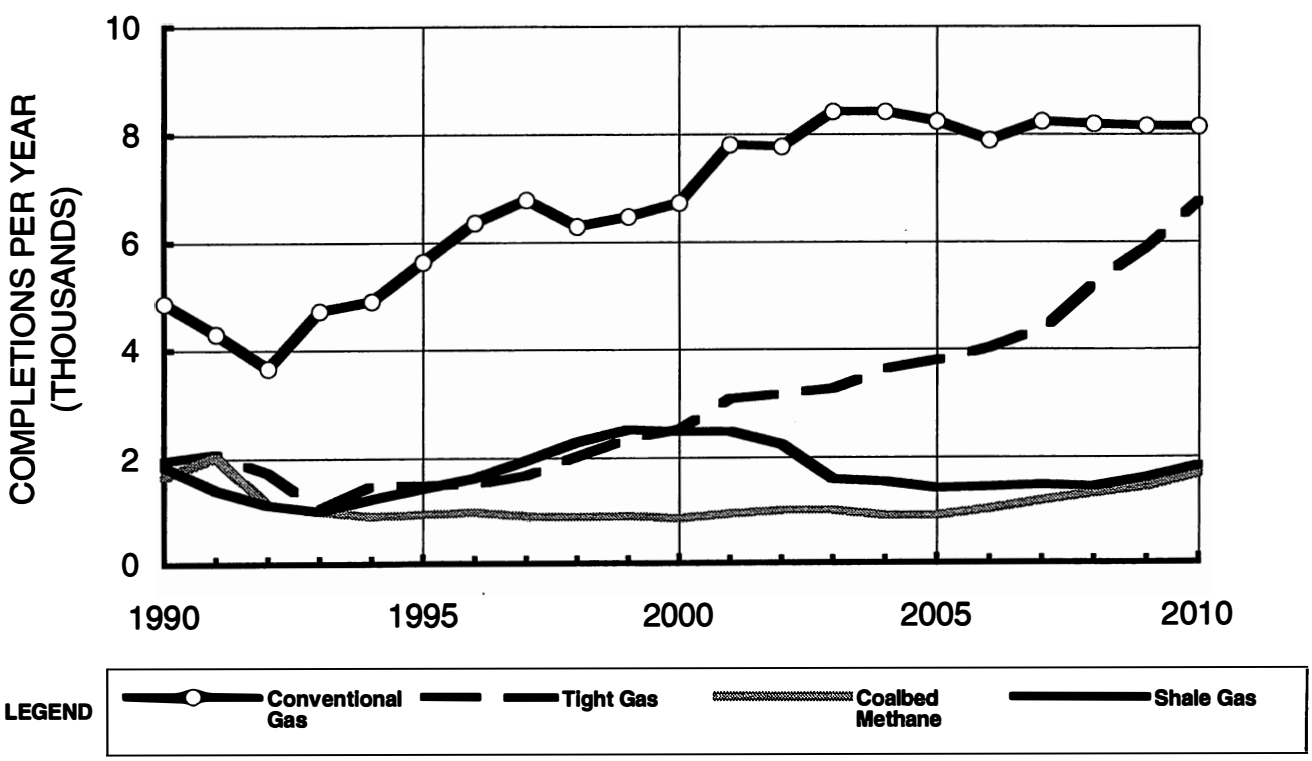


Figure 3-10. U.S. Lower-48 Gas Well Completions by Type of Resource—Reference Case 1.

TABLE 3-5

REFERENCE CASE 2 SUPPLY SUMMARY
LOW ENERGY GROWTH SCENARIO

	1991	1995	2000	2005	2010
Production, TCF/year					
Domestic	17.5	17.2	16.4	17.7	17.7
Imports	1.8	2.5	2.7	2.9	3.1
Total	19.3	19.7	19.1	20.6	20.8
Deliverability					
Utilization, %	83	94	96	96	96
Wellhead Price					
Texas Gulf Spot, 1990$/MMBTU	1.27	1.61	2.36	2.45	2.74
Gas to Oil, %	40	60	81	77	80
Well Completions					
Gas	9,800	6,700	9,100	12,500	12,200
Proved Reserves, TCF					
Lower-48	156	136	122	125	127
Canadian	70	63	58	61	61
Memo—Oil Price					
1990$/Barrel	18.38	15.50	17.00	18.50	20.00
1990$/MMBTU	3.16	2.67	2.93	3.19	3.45

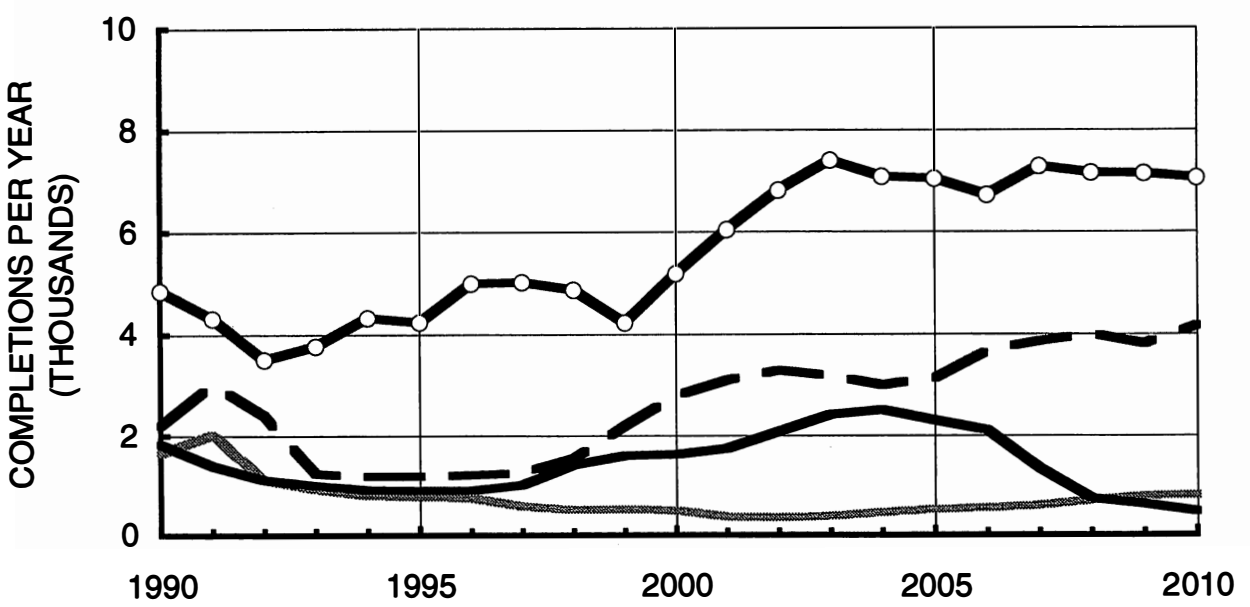


Figure 3-11. U.S. Lower-48 Gas Well Completions by Type of Gas Resource—Reference Case 2.

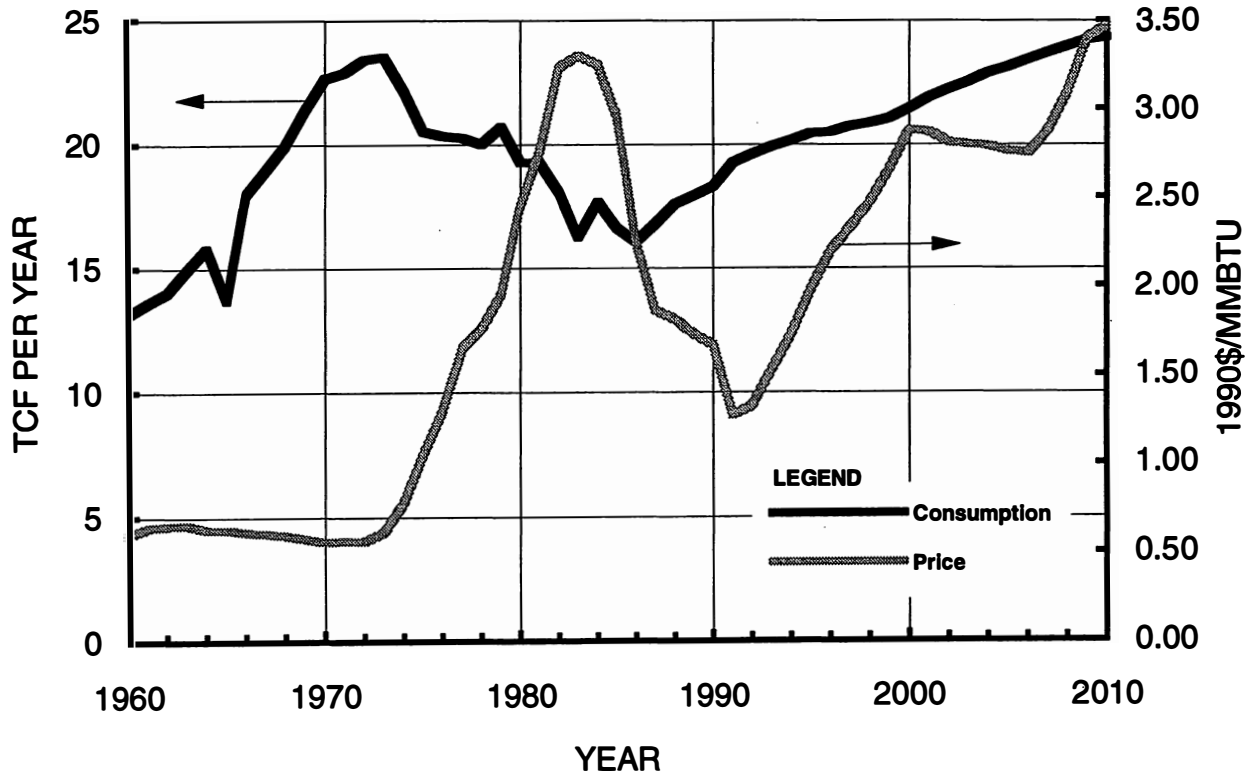


Figure 3-12. U.S. Lower-48 Consumption and Texas Gulf Spot Wellhead Gas Price—Reference Case 1.

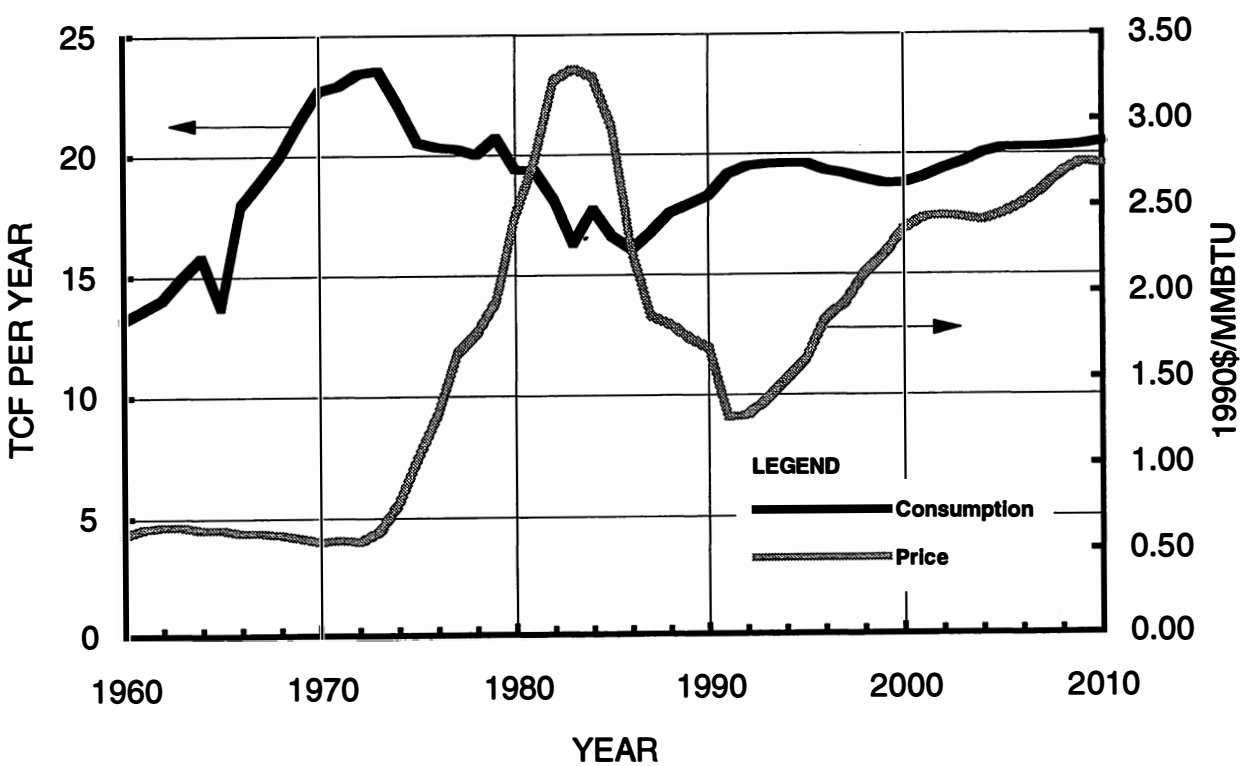
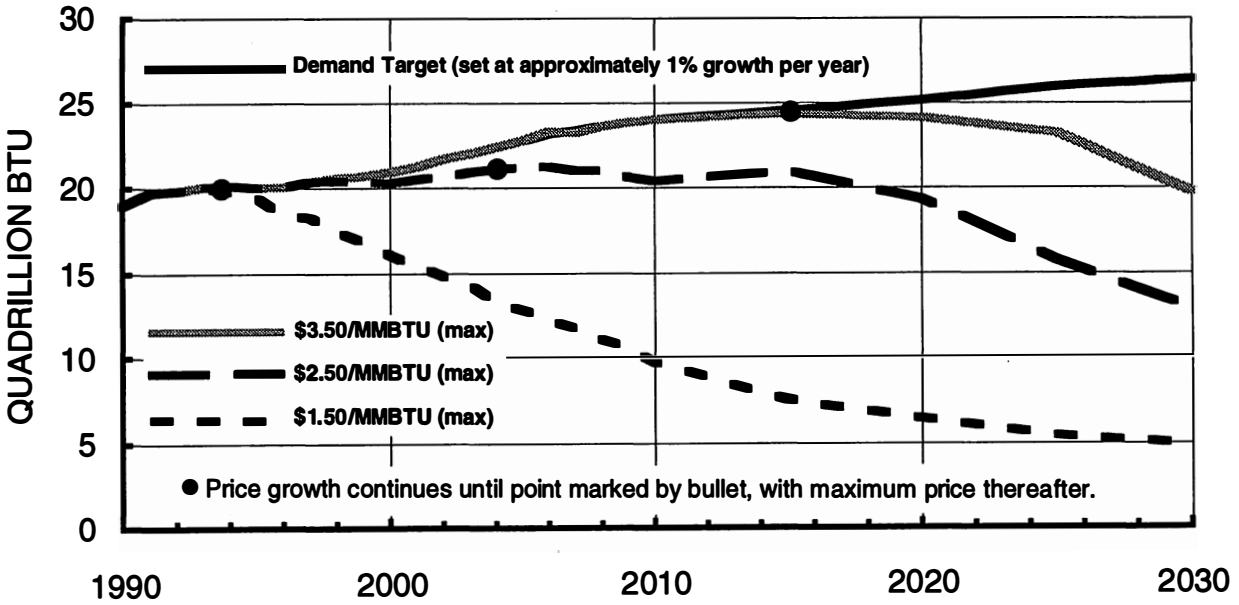


Figure 3-13. U.S. Lower-48 Consumption and Texas Gulf Spot Wellhead Gas Price—Reference Case 2.



NOTES: 1. Assumes technology advancing throughout the period.
2. Prices are in 1990$ per million BTU for Texas Gulf Spot.
3. Demand target fully satisfied through 2030 at prices which do not exceed $4.50/MMBTU.

Figure 3-14. Long-Term Gas Supply at Various Maximum Wellhead Price Levels.

price assumption for 2030, this yields a wellhead BTU equivalency for gas between 60 and 70 percent.

Import dependence would rise from 11 percent today to 25 percent in 2030, primarily gas from Canada. While this is a substantial increase, it remains modest compared to today's U.S. 50 percent oil dependence and compared to other developed gas markets around the world. For example, Japan is essentially 100 percent dependent on import LNG for its gas supply and willing to pay approximately 100 percent of crude oil equivalency as well.

Figure 3-15 shows the mix of domestic supply for the maximum case. Conventional supply begins to drop around 2010, and is increasingly replaced by tight sands production.

Figure 3-16 compares cumulative production over the 40 years to the resource base expected to be available to support continuing development activity. Note that the starting point includes 760 TCF already produced as of 1990. The resource base is expected to continue growing as new technology becomes available. Even in 2030 the remaining resource base should be substantial.

Supply Curves

Another traditional approach to defining long-term supply potential is to subdivide the recoverable resource base into various cost/price categories. Although such an approach cannot adequately take into account dynamic factors such as time-dependent reserve appreciation, technology advancement, and the changing competitiveness of alternative fuels, it does provide a means of visualizing the underlying economic resource potential and the important contribution technology advancement can make in increasing that potential.

Utilizing explicit detailed assumptions similar to those previously stated for the modeling work used to develop the Reference Cases, aggregate "supply curves" can be developed for specific fixed price and technology assumptions as shown in Figure 3-17. Several conclusions can be drawn from analysis of these curves:

- By definition, the 160 TCF proved reserves are economic under current technology and wellhead prices. Even at $1.50/MMBTU, reserve additions are likely to nearly double this figure.

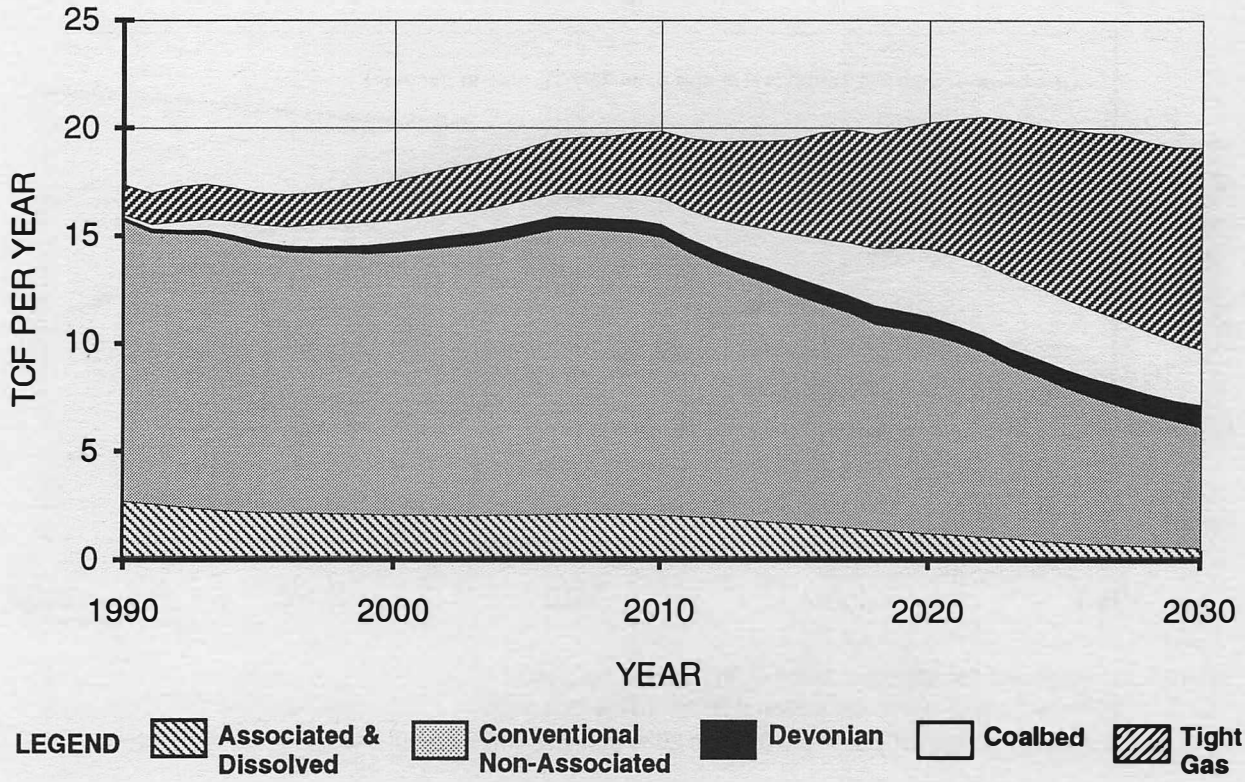


Figure 3-15. Total Lower-48 Dry Gas Production—Maximum Demand Case.

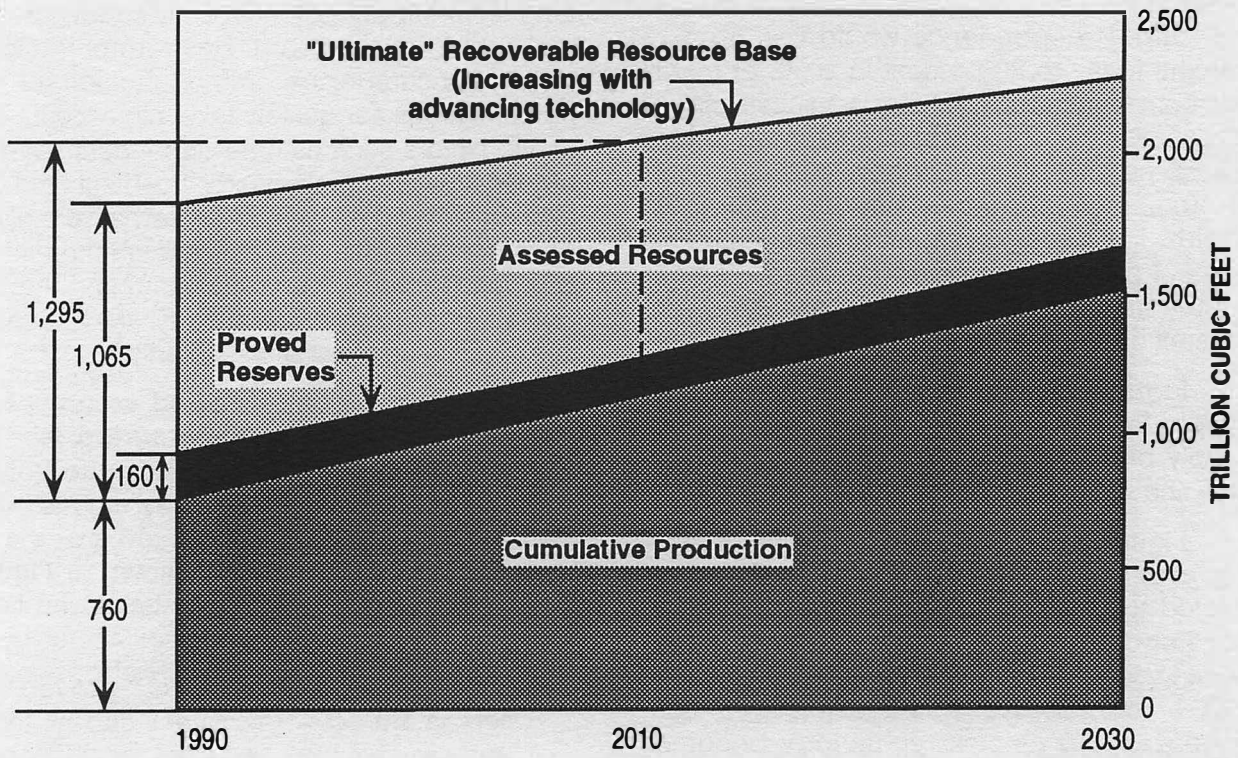


Figure 3-16. Gas Resource Base.

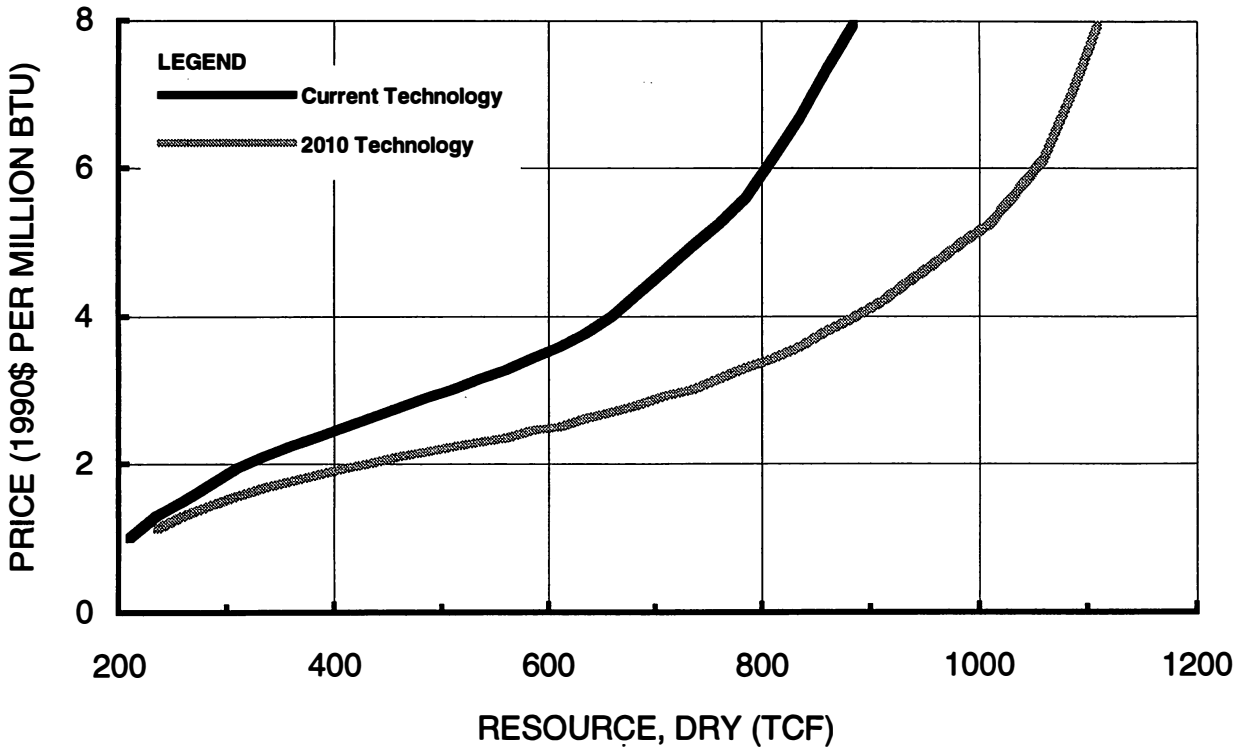


Figure 3-17. U.S. Lower-48 Gas Supply Curves.

- At prices commensurate with Reference Case 2 of $2.50/MMBTU (1990$) in 2010, the estimated economic resource, even with today's technology, is approximately 400 TCF. The significant potential of technology gain is evident at this price assumption. Assuming 2010 technology, the economic resource estimate increases to 600 TCF. Even excluding import potential, this is a 35-year supply at current domestic production levels. In a dynamic world, technology gain within such a 35-year span would likely increase the economic resource further.
- At $4.50/MMBTU (1990$), approximately 950 TCF is economic under 2010 technology assumptions. This represents the equivalent of a 60-year supply and suggests an immense menu of exploration and development opportunities available over time to replace and supplement today's production. It is of interest to note that an increase from $1.50 to $4.50 over 60 years represents an annual real growth rate of less than 2 percent/year—clearly substantial over such a long time but rather small annually in comparison to the ± 50 percent swing seen in 1992 monthly wellhead prices alone.

Supply Sensitivities

The NPC does not consider either of the Reference Cases to be a forecast of the future so much as a disciplined means to look at the interaction of supply and demand potential within a reasonable framework for analysis. Therefore, to establish the range of potential upside opportunity and downside risk, a number of sensitivity cases were developed and analyzed as summarized below. For discussion purposes all are described relative to Reference Case 1.

Higher New Field Discovery Potential

Assessment of new field potential involves detailed basin-by-basin evaluation of geologic potential attributing known results elsewhere to new areas with similarities. Given statistical uncertainty, the study recognizes that there may even be basins that have been completely overlooked (for example the Norphlet trend in

the Gulf Coast Basin was only given limited recognition as recently as 10 years ago). Although 50 TCF has been included in the NPC resource estimate to accommodate this possibility, the estimate of new fields potential could still be conservative by as much as another 100 TCF. Should this prove to be the case, additional supply would become economic, increasing gradually to 1 TCF/year by 2010. Competitive price could be as much as $0.50/MMBTU lower in the later years, anticipating that larger typical new field size would lower unit development costs.

Higher Import Potential

Canadian resources are relatively less exploited than those in the lower-48 states. Upside potential could be as great as 50 percent compared to the NPC estimate for the Western basins. There is also the possibility that Mexico's 252 TCF resource base will be developed at a pace to displace imports from the United States and bring net exports of 0.5 TCF/year to the United States by 2010. Together these could add over 1 TCF/year to U.S. markets by 2010 and reduce the competitive price by about $0.50/MMBTU. Conversely, were Canada to impose export growth restrictions, U.S. imports could be reduced 0.5 TCF with competitive price raised approximately $0.25/MMBTU.

Rapid Tight Sands Development Potential

Although the NPC study work on tight sands suggest impressive potential in the coming years, there is uncertainty as to the practical pace at which activity buildup can occur. Accordingly, a judgmental growth rate restraint of 20 percent/year was imposed on tight sands development investment in the Reference Cases. Accelerated development without such an assumption yields an additional 1 TCF/year by 2010.

No Tight Sands Technology Advance

Conversely, technology advance is expected to be rapid for tight sands as activity levels increase above today's rather modest programs. Should the assumed 2 percent/year recovery gain not materialize, production by 2010 would likely be 1 TCF/year lower.

High Environmental Regulation

Recognizing the exposure to more stringent regulation than assumed for the Reference Cases under a balanced cost/benefit philosophy, a sensitivity case was defined incorporating additional regulatory initiatives based on publicly proposed, more stringent interpretation or amendment to RCRA, CAA, SDWA, and CWA. While this does not represent a "worst case," it does incorporate substantially more aggressive environmentally motivated constraints on supply than assumed for the Reference Cases. For example, the sensitivity case assumes RCRA would be amended to apply more extensively to exploration and production activities than assumed for the Reference Cases. As a specific illustration, tanks would replace surface impoundments (pits) in most situations. In combination with other specifically defined changes, individual drilling costs for new wells in this sensitivity case would be increased by 50 percent. Modeling results indicate supply would be decreased at least 2 TCF/year by 2010 due to earlier well abandonment and reduced drilling caused by higher capital and operating costs.

Forecast Uncertainty

The range of supply required to satisfy demand for the moderate versus low energy growth scenarios (Case 1 vs. Case 2) illustrates the hazard and uncertainty facing the producer community in coming years. Obviously, the subjective assumption of "perfect foresight" is not going to occur in the real world.

As an alternative to the presumption of such foresight, it is possible that demand will continue to linger for a few years near the levels of the low energy growth scenario while perceptions of a stronger market bring forth new supply sufficient to meet the higher needs of the moderate energy growth scenario—or vice versa. This could be accentuated if regulatory reform is delayed or otherwise less than successful. Price movements could be erratic as a result.

As seen in Figure 3-18, two sensitivities using different assumptions on near-term reserve additions and deliverability demonstrate the degree to which price instability could occur if market signals are poorly transmitted. As regulatory and contracting practices evolve in

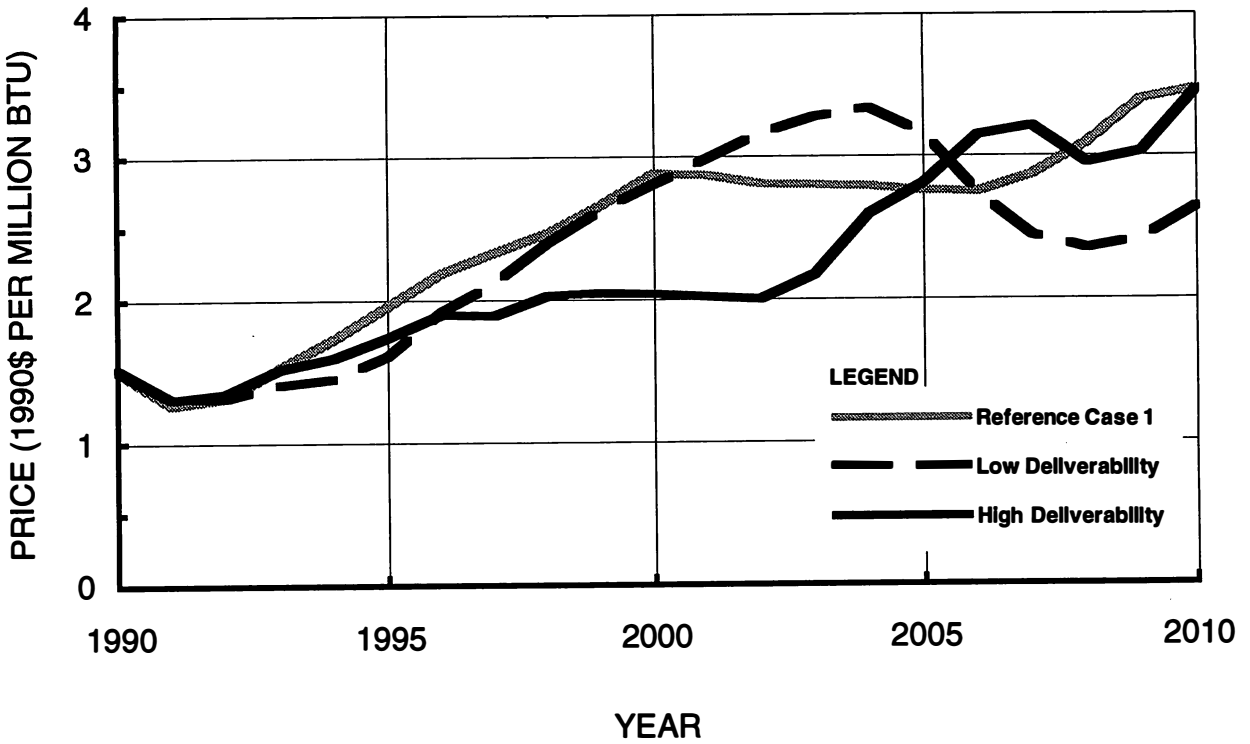


Figure 3-18. Price Uncertainty—Texas Gulf Spot Wellhead Price.

response to market need, new contract forms and new risk management tools such as the futures market can be used to minimize such price swings for producers and consumers alike. Increased flexibility to fully utilize transportation and storage systems can also cushion market cycles.

POTENTIAL CONSTRAINTS AND OPPORTUNITIES FOR SUPPLY

Producer/Service Company Rebound Potential

Rather than relying on specific numerical projections of the future for confidence in long-term supply security and reliability, it is perhaps more appropriate to look at underlying fundamentals of the industry.

Recent industry downsizing and declines in drilling activity in North America have raised concern that natural gas supply may prove unable to respond to future market needs. While driven largely by oil considerations rather than natural gas, the statistics are nevertheless unpleasant. Gas well drilling has reached its lowest point in over 15 years. Jobs in the oil and gas extraction sector are down 50 percent in ten years. Data indicate somewhat lower natural gas reserve replacement figures for 1991 and the possibility of significantly lower replacement in 1992. There is concern that consequent decline in excess deliverability could bring decreased supply reliability. Recent decisions in Oklahoma and Texas that modify historical prorationing procedures compound the concern.

The NPC believes these events are primarily the result of economic signals transmitted by the combined influence of market demand, domestic recession, and better investment opportunity elsewhere. Therefore, they are correctable with time if market signals so dictate.

There is evidence from the past that supply will come forth as market signals dictate. Admittedly, past swings, both up and down, were exaggerated by regulatory distortions. Nevertheless, the industry's ability to respond was clearly demonstrated. The pace at which supply responded positively in the 1970s to increased price incentives suggests supply response time can be rapid indeed! Figure 3-19

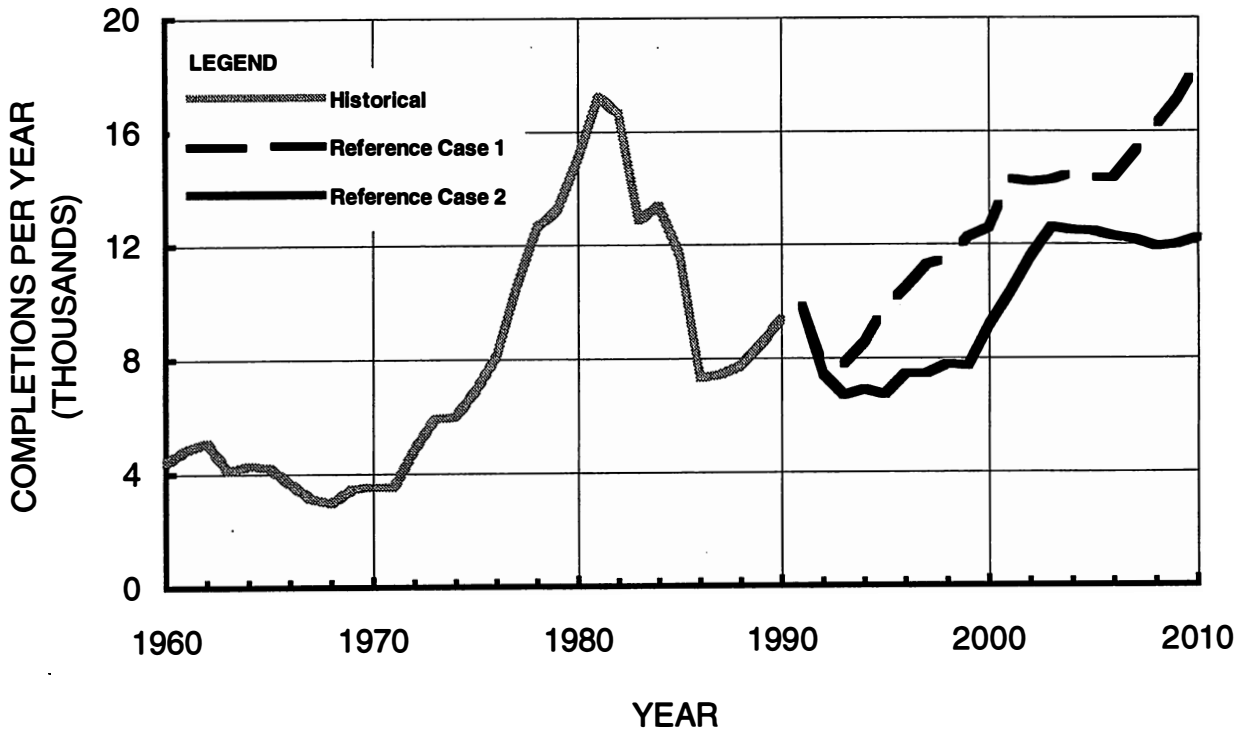


Figure 3-19. Gas Well Completions.

compares drilling activity response during that period to the projected requirements under Reference Cases 1 and 2. Hopefully, with the ongoing transition to a market responsive rather than regulatory responsive business environment, lead times for supply can be even shorter than in the past.

Examination of resource potential and producer/service company capability suggest current economics for both oil and gas and cost efficiency programs, not lack of gas prospects, are driving the current industry contraction. To the degree that greater efficiency is the result, ability to respond quickly to growth opportunity for gas will be enhanced rather than reduced. Additional evidence of "rebound" potential comes from a survey of recent R&D expenditure patterns for producers and service companies. Expenditures directed at supply-side technology appear to be holding steady, and in some cases, increasing for the survey participants. Furthermore, asset sales, and restructuring programs by many of the majors may have the appearance of overall domestic industry cutback but may in fact be primarily a shift toward a larger role for independents and other smaller producer companies.

Decline of Unused Deliverability

It is anticipated that deliverability utilization will increase over time as price deregulation eventually brings overall supply/demand into balance, and producers reinvest as needed to offset depletion and competitively meet overall demand growth. While extra deliverability has been available to help meet seasonal balancing needs, this will increasingly be met by fuel switching, "unbundled" gas storage, and transportation flexibility.

An examination of the historical regulatory actions that have contributed to the so-called "gas bubble" suggest that the excess deliverability it represents is more a carryover of past market distortions than current market signals. While it is possible that optimistic perceptions of market strength could continue to perpetuate a "surplus," as appears to have been the case for the last few years, there is no assurance that it will since spot purchases, which currently dominate, provide no incentive for idle capacity. Presumably, over time individual firm and longer term supply arrangements (working in conjunction with storage and transportation arrangements) will

evolve, instead, to ensure that gas supply reliability is maintained.

Contract Diversity

The foregoing discussion of modeling results has centered on assessment of the view that supply can be maintained and that the business can "rebound" from today's low activity levels. Regulatory reform and contract diversity are essential elements in providing an appropriate business environment to ensure that it will.

Changes over the last decade that brought collapse of the old long-term contract structure along with continuing uncertainty in the natural gas regulatory and legislative arena have dramatically changed contracting practices. This has resulted in the emergence of a large spot market. While the spot market is likely to remain the preference for many participants, a continuing contract uneasiness prevents many other buyers and sellers from entering into medium- and long-term contracts. Although it would clearly be a mistake to try to return to the old highly regulated, rigid contract structure of the past, the uncertainty and instability that prevail today must be overcome.

The NPC believes it would promote growth of the free-market system to encourage the use of a wide variety of contract relationships between buyers and sellers. Individually negotiated, mutually beneficial contract relationships between buyers and sellers will help stabilize the market, increase demand, and provide more security on an as needed basis. Modern risk management tools can be used in conjunction with modern, innovative contracting approaches to protect buyers from uncertainty, encourage timely supply additions, and reduce general price volatility.

Both state and federal government policy and regulation can provide the right business environment so that such contracting practices will evolve as market signals and need dictate. Specifically, policy matters at the federal and state level should adopt principles that recognize the need for and merits of natural gas and the necessity to provide stable access to supply. They need to adopt practices that reestablish confidence of buyer and seller alike in the sanctity of contracts by reducing the exposure to retroactive changes and unreasonable "prudency" reviews. These subjects are dealt with in greater detail in Chapters Six and Ten.

Import/Export Opportunities

It is the view of the NPC that the gas market will operate most efficiently based on free-market principles. This principle applies domestically and it should apply to import/export gas as well. The existing U.S./Canada free trade agreement is based on this principle.

In the near term, international natural gas trade can serve to strengthen domestic production capabilities by establishing new markets for gas sales. Although foreign gas supplies are expected to increase their market share in this country, natural gas export sales to Mexico, Japan, and Canada are also expected too. In the long term, additional competitively priced imports to the United States will add to the diversity of supply sources and the resources available to back U.S. demand growth.

The United States and many of its trading partners have been making serious efforts to liberalize their trade policies. The NPC supports continuation of this effort through such negotiations as the North American Free Trade Agreement (NAFTA) and other undertakings. However, it also finds that the NAFTA results as reported out fell short of this objective for the natural gas sector, due to several exceptions retained by Mexico for the energy sector. Over time, further effort by the United States is appropriate in support of natural gas exports to Mexico commensurate with standing rights for Mexican gas to be imported into the United States.

Much of the world's oil and gas business activity is U.S. based, historically rooted in domestic operations. Therefore, there is global value that can accrue to the U.S. economy in supporting competitive principles in the United States in exchange for equivalent undertakings by our trading partners. Reciprocal free trade efforts should seek competitively based, nondiscriminatory operating and ownership rights in all phases of the natural gas business. Specifically, failure of U.S. negotiators to challenge the Mexican constitutional limitations on oil and gas reserves development would work to the long-term disadvantage of increasing North American natural gas supply and consumption.

Fiscal Policy

Taxes and other government imposts are important factors in shaping the economics of natural gas exploration, development, and production. While resource costs and realized prices are the prime determinants of natural gas supply economics, fiscal systems can be used to both increase and decrease the economic cost of supplying natural gas to the U.S. market. While it would not be appropriate to seek preferential treatment, a constructive natural gas policy for the United States should incorporate a fiscal component that minimizes disincentives to finding new gas sources, developing new gas technologies, and fully exploiting known gas resources.

The U.S.-type tax system places a heavy tax burden on general savings and capital formation. In addition to generally applicable taxes such as income and property, natural gas incurs fiscal burden in the form of severance taxes, royalty, lease bonus payments, etc.

Of particular note is the alternative minimum tax (AMT) that acts as a disincentive against investment and contains several features that specifically penalize gas investments including ones made for environmental compliance.

In the depressed price environment that has prevailed in recent years, many natural gas producers who are in a loss position with regard to the regular income tax have found themselves faced with substantial AMT liabilities because they have remained active in the natural gas business.

One element of the U.S. tax policy that applies specifically to natural gas comes under Section 29 of the Internal Revenue Code. This income tax credit applies to nonconventional gas. Currently it is set at 53¢/MCF for tight gas and approximately 90¢/MCF for other types including coalbed methane. Especially for coalbed methane, and despite generally low gas prices, the Section 29 incentive has clearly worked to advance nonconventional technology and brought significant production into the market. The current incentive, as applied to new drilling, expires at the end of 1992. Opposition to extension centers on concerns of market distortion and fairness of such a large credit compared to conventional gas, which has limited price incentive and the inevitability that future conventional gas discoveries will generally be smaller or deeper and more expensive than in the past. Proponents of extension argue proven effectiveness as a stimulant to technology and the absence of entry barriers for industry participants.

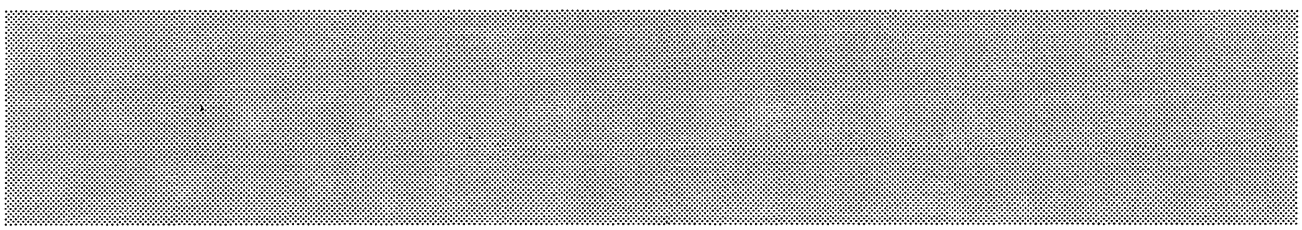
Past Perceptions and the Need for Supply Education

Both industry and government share responsibility for the poor identity of natural gas. The NPC believes both must participate in an effort to correct public and consumer misunderstanding of natural gas supply potential and to establish an identity for natural gas that stands on its own merits.

This NPC study itself can serve as a tool in NPC participating member company, DOE, and possibly White House statements, and press releases and report distribution.

While no substitute for regulatory reform and customer-oriented contracting practices, there are informational and educational steps for industry and government to consider. Industry should intensify its efforts to increase public/consumer understanding through joint industry sponsored education programs. The recently formed Natural Gas Council is an example of the approach that can be taken and utilized at the general public as well as the major consumer level.

Additional steps the DOE should consider include a reexamination of its supply information base and distribution process to ensure that state commissions better understand supply dynamics, including recognition of the lead time needed to translate demand signals into new supplies. For example, the DOE could sponsor a conference on energy data and forecasting.



CHAPTER FOUR
MARKET OPPORTUNITIES

OVERVIEW

Numerous studies confirm that natural gas is widely perceived as a valuable fuel with numerous applications and advantages. Moreover, natural gas is an environmentally clean alternative to other fossil fuel sources. These factors can help natural gas to increase its share of the energy market but will not be sufficient in themselves to ensure this result. The notion that gas will sell itself is unrealistic. All segments of the gas industry will have to work to retain existing customers as well as address and overcome obstacles to the addition of new customers. Among these obstacles are the perceptions of some, particularly electric generation customers, that the gas industry is: unreliable; potentially unable to meet its commitments; unresponsive to its customers' needs; and lacking the capability to market its product. Accordingly, the gas industry must demonstrate to end users that mechanisms exist for markets to manage price and supply volatility, and the delivered price of gas is and will be economically competitive. A positive step in this direction has been the recent formation of the Natural Gas Council, bringing together key segments of the gas industry with the avowed goal of increasing gas demand.

Although certain obstacles to the growth of natural gas demand have been identified, these obstacles are manageable. Aggressive marketing efforts, cooperation, hard work, and excellent customer service are the keys to success. Focus group interviews identified the need for organizations within the gas industry to improve their marketing capabilities. Companies are responding to these concerns and are developing marketing organizations and affiliates to identify and serve customer needs. Traditional sectors of industry, from producers to pipelines and local distribution companies, as well as new entrants such as aggregators and marketers, now have the potential to deal directly with the consumer. While competition within the industry is increasing and customers are benefiting, industry participants have been thrust into new competitive roles and the adjustment is not yet complete.

The adversarial nature of the regulatory process has detracted from the industry's ability to market its product. Industry regulations continue to evolve, and until stabilized, will cause a measure of uncertainty in the market. FERC Orders 380, 436, 500, 528, and the recent series of 636 orders have dramatically changed the gas industry.

Conservation and improved energy efficiency are being stimulated by state Demand Side Management and Integrated Resource Planning (IRP) requirements, environmental regulations, and appliance efficiency standards. While these programs will curtail the rate of growth in overall energy demand, they will improve the value being provided to the customer and will potentially augment the competitive position of gas applications.

The markets for natural gas are highly diverse, ranging from individual residential

customers whose consumption can be as low as 30 thousand cubic feet (MCF) per year to large industrial facilities and power generation installations consuming in excess of 50 billion cubic feet (BCF) per year. The NPC Reference Cases provide a numeric framework from which to discuss the growth potential of the four traditional consuming sectors. For the two scenarios developed for the study, Figures 4-1 and 4-2 display the model results for the distribution of the various energy sources contributing to primary energy consumption in the markets consuming natural gas. Table 4-1 contains a breakdown of the calculated gas consumption by market sector. In Reference Case 1, gas consumption grows in both absolute and relative terms, although coal is projected to grow at a faster rate than gas in the second decade due to the increasing price of gas relative to coal. Gas's market share remains essentially constant in Reference Case 2, due to slower demand growth in the industrial sector. Slower industrial sector demand growth results from assumptions of more aggressive conservation measures in Case 2. In both Cases, increased consumption of natural gas is the major reason that residual and distillate fuels, which are largely imported, do not grow. It should be noted that these cases do not constitute an NPC forecast of future gas demand.

CONSUMING SECTOR OPPORTUNITIES

Residential and Commercial

The residential and commercial markets form the traditional core and backbone of the natural gas industry. Natural gas is used in 55 percent of single-family dwellings nationwide. In 1990, the residential customer class consumed approximately 4.5 quadrillion British thermal units (QBTU) of natural gas, while the commercial class consumed 2.7 QBTU. Of these deliveries only 5 percent are estimated to have been delivered on a less than firm basis.

The capital intensive nature of local distribution companies (LDCs) coupled with the obligation to serve their core firm-sales customers explains the price differential between the spot price of gas and the delivered firm sales price. Its notable that firm sales customers are and have been provided totally reliable gas service at competitive prices.

Residential

Major forecasts (American Gas Association, Energy Information Administration, Gas Research Institute) project the total number of residential gas-consuming customers to continue to increase beyond the year 2010. This

TABLE 4-1

LOWER-48 NATURAL GAS CONSUMPTION
(Quadrillion BTU per Year)

End-Use Sectors	1990	Reference Case 1 2010	Reference Case 2 2010
Residential	4.5	4.9	4.7
Commercial	2.7	3.5	3.1
Industrial	7.0	8.9	6.1
Electric Utility	2.9	5.4	4.9
Total End Use	**17.1**	**22.7**	**18.8**
+ Lease/Plant Fuel	1.1	1.3	1.1
+ Transmission Fuel	0.6	0.9	0.7
+ Exports/Misc.	0.2	0.2	0.7
Total Consumption	**19.0**	**25.0**	**21.3**

Note: Totals may not agree due to rounding.

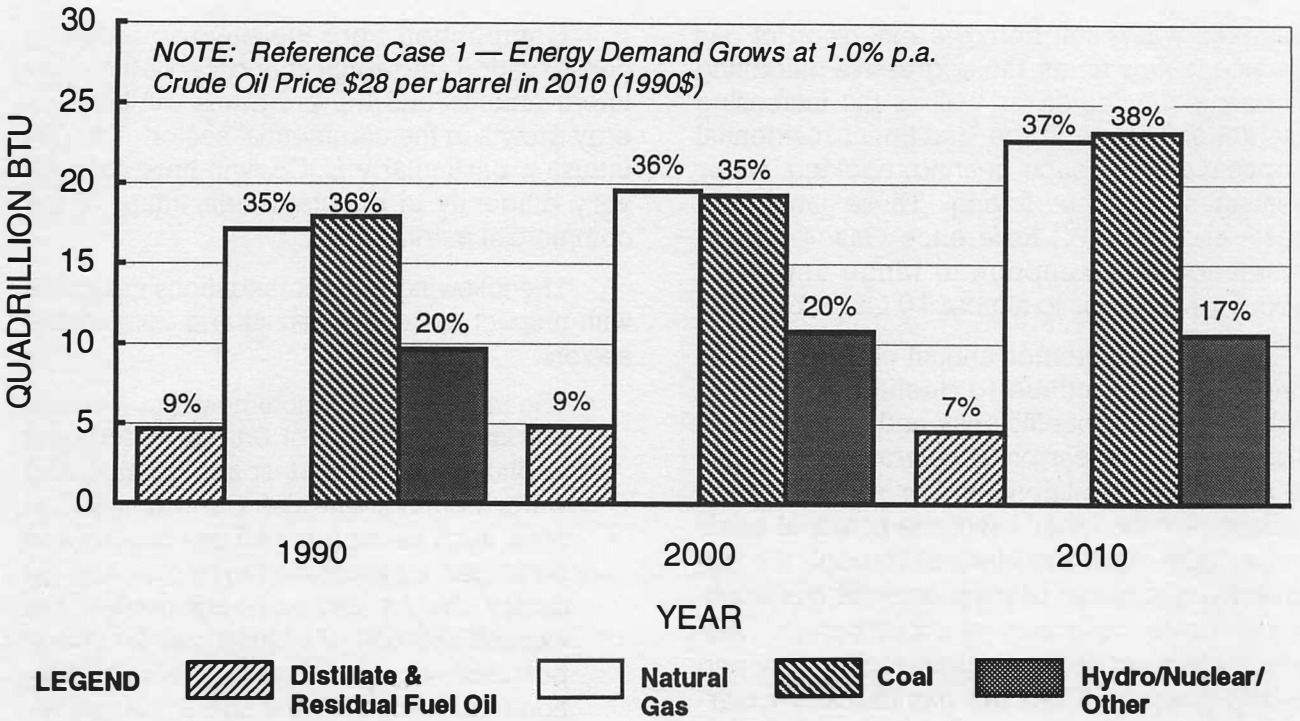


Figure 4-1. Primary Energy Consumption and Market Share—Reference Case 1.
(Excludes Coking Coal, Oil Feedstocks, and Liquid Transportation Fuels;
Gas Data Exclude Lease/Plant Fuel, Transmission Fuel, and Exports)

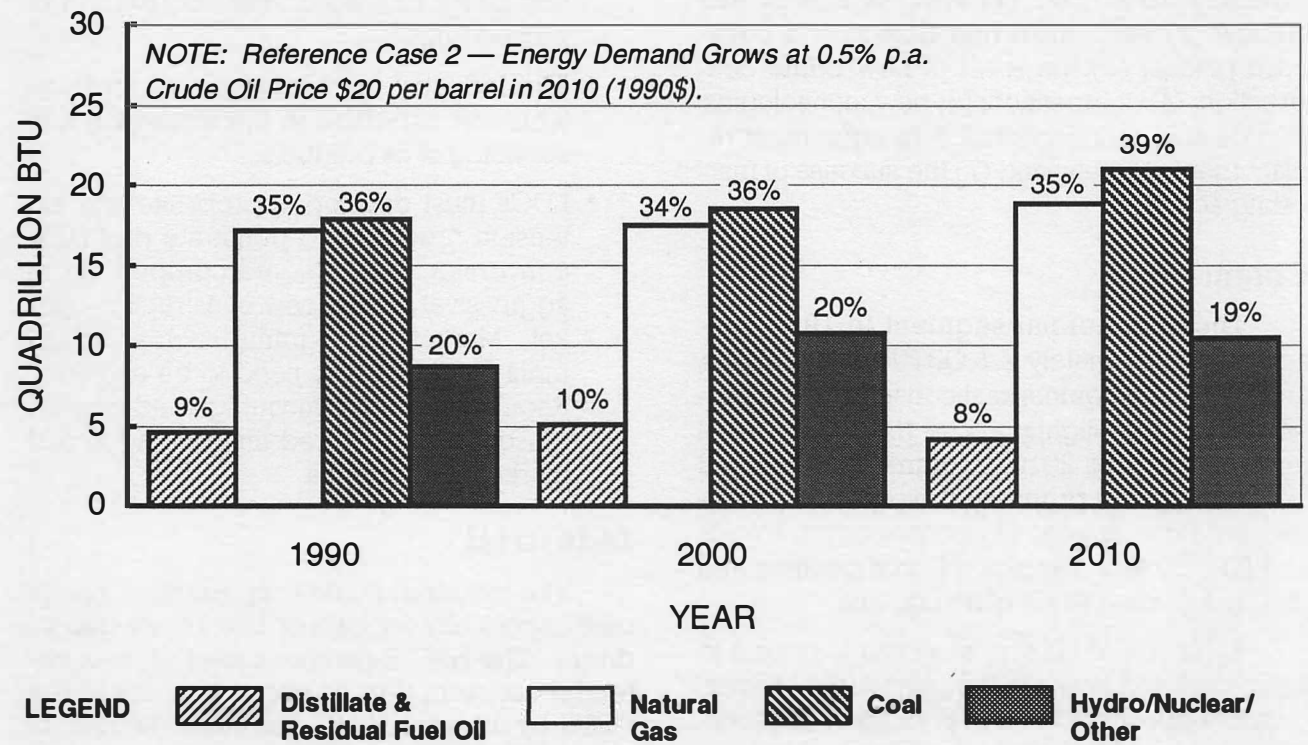


Figure 4-2. Primary Energy Consumption and Market Share—Reference Case 2.
(Excludes Coking Coal, Oil Feedstocks, and Liquid Transportation Fuels;
Gas Data Exclude Lease/Plant Fuel, Transmission Fuel, and Exports)

increase will result from the extension of gas service to new areas, the aggressive marketing of new technologies, as well as the increasing market saturation in the traditional residential applications of space heating, cooking, water heating, and clothes drying. These same forecasts and the NPC Reference Cases project residential consumption to range anywhere from current levels to almost 5.0 QBTU by 2010.

The per-customer annual consumption is projected to continue to decline due to improved equipment efficiency and conservation. This trend may possibly accelerate in response to economic conditions and/or regulatory initiatives. On the other hand, the potential exists to partially offset this decline through the aggressive marketing of supplemental gas appliances to existing and new customers. Advances in electric heat pump technology and its promotion will test the gas industry's marketing abilities in its core space-heating market, particularly among new residential construction, and highlights the need for the commercialization of advanced technologies, such as the gas heat pump, in order to remain competitive.

Change in residential gas consumption is primarily driven by: (1) effect of energy efficiency; (2) residential rate design and delivered prices; (3) the level of new home construction; (4) competition; (5) new technologies; (6) possible fuel substitution in equipment replacement markets; and (7) the success of marketing activities.

Commercial

The commercial segment in 1990 consumed approximately 2.7 QBTU of natural gas, and traditional commercial consumption is projected to grow slightly above the current level through the year 2010. Commercial demand for natural gas is primarily driven by: (1) commercial floor space; (2) conservation trends and IRP; (3) technologies; (4) competition; and (5) the delivered price of natural gas.

Retention of current business is critical to future demand levels in the commercial sector. Growth opportunities lie in packaged cogeneration and in advanced gas cooling technology. The industry faces a major challenge in penetrating the high-rise office/apartment market.

Competition from the electric industry, conservation, federally mandated efficiency improvements, and IRP programs will limit energy growth in the commercial sector. The gas industry, particularly LDCs, will have to work very diligently to maintain their share of the commercial market.

The following recommendations are made with respect to the residential and commercial sectors:

- The industry as a whole needs to focus its marketing efforts not only on traditional applications, such as space heating and water heating, but also on new applications, such as commercial gas cooling and packaged cogeneration systems. The industry should also work aggressively to expand the use of natural gas for transportation, e.g., commercial fleets and at-home refueling facilities for natural gas vehicles.
- The industry must lower the overall cost of natural gas to the customer by improving the cost-effectiveness of providing gas services, as well as encourage the development and use of efficient technologies, conservation measures, and fuel substitution programs within the context of IRP proceedings.
- The industry must increase its levels of technical expertise in the marketing and servicing of its products.
- LDCs must develop appropriate line extension programs to penetrate profitable conversion markets and compete more aggressively in the new construction market. Marketing programs, such as equipment financing, also need to be explored. Regulators should encourage and support reasonably structured line extension and marketing programs.

Industrial

The industrial market represents a significant opportunity for gain or loss by the gas industry. The NPC Reference Cases show a potential consumption of between 6.1 and 8.9 QBTU by the year 2010. For 1990, the Energy Information Administration reported industrial energy consumption of 29.8 QBTU of which natural gas represented 7.0 QBTU or 23.5 percent.

Since 1960, industrial energy consumption has grown from approximately 20 QBTU to the 1990 level of 29.8 QBTU, or approximately 1.3 percent compounded annually.

Industrial gas demand is primarily driven by: (1) the degree to which the U.S. economy converts from energy intensive manufacturing industries to service industries; (2) changes in the energy intensity of these industries; (3) general economic growth; (4) conservation/efficiency trends; (5) impact of new technologies; (6) relative delivered fuel prices; (7) the success of the gas industry's marketing efforts; and (8) regulatory constraints.

The industrial market sector has undergone a major restructuring during the last decade as a world market has emerged where quality and productivity have become dominant considerations in business decision making along with the continuing need to control costs and improve operational efficiency. Although manufacturers are still heavily motivated by return on investment in making capital decisions related to energy process choices, the increasing need to meet world class quality standards and address environmental concerns will make the energy decision making process more complex in the future. Industry will adopt energy efficient, productive, and cost-effective manufacturing processes that will enable them to compete effectively in a world market where product quality and customer satisfaction will determine success. To the extent natural gas and related equipment meet these criteria, future growth in demand should be achieved.

Today's industrial energy marketplace is the most competitive sector served by the gas industry. Decision makers in the industrial segment are sophisticated energy and process equipment buyers having a wide range of alternatives from which to select. At the industrial end-user level, the gas industry faces increasing competition for the industrial process market where gas has been traditionally the preferred option. Electric technologies, championed by the electric industry, threaten to displace natural gas. Supporting the adoption and use of high efficiency gas equipment is the approach that the gas industry needs to take to counter this threat.

While competition by other energy sources is formidable, opportunities exist to expand the consumption of natural gas in the industrial market sector. The Clean Air Act Amendments of 1990 provides an opportunity for the industrial sector to take advantage of allowance trading. Emission control, waste recycling and remediation, as well as conversion of coal boilers to natural gas or co-firing are instances where industrial facilities may create valuable emission allowances for trading. The value and incentive to encourage the creation of credits will vary by industry and region but may provide an incentive for gas penetration into markets where gas is less than fully utilized.

Significant opportunities are also presented by the potential for gas-fired cogeneration systems to meet electric generation requirements, while providing steam process heat as part of an overall efficient system. Securing "steam hosts" will aid in developing this opportunity.

Other niche market opportunities within the industrial sector that can be realized by substituting natural gas processes for electric energy requirements are: (1) gas engine drive for air compressors and process chilling; (2) gas rapid heating technology for preheating parts prior to induction heating; (3) new technologies such as the gas vacuum furnace to compete head to head against electric units in areas where they hold large market shares; and (4) displacing coke in existing steel blast furnaces.

The opportunities and risks for the gas industry are more apparent in the industrial market than in the other major sectors. The combination of gas industry marketing ability interlinked with new end-user technology is the key to maintaining the gas option in the industrial market.

In the industrial market, it is recommended that the gas industry:

- Aggressively pursue opportunities to convert industrial facilities to natural gas by demonstrating the capability of gas processes to provide environmental, operating, quality, and productivity benefits in comparison to the customer's existing coal, electric, or fuel oil.
- Provide added value to the customer by providing information on the most efficient

use of the product, through education on newly emerging gas technologies, and by assistance in obtaining necessary governmental permits.

- Leverage its resources by encouraging increasing participation in gas industry initiatives, such as the Industrial Gas Technology Commercialization Center.

Electric Generation

The potential for increased consumption of natural gas for electric generation is attracting considerable attention in the natural gas and electric industries, and among government officials, including regulators. Several factors contribute to this attention:

- Electric usage accounts for a large and growing share of the U.S. energy demand.
- Natural gas has important environmental advantages over competing fuels in the electric generation market.
- Advanced gas-fired generating units, particularly combined-cycle units, have high efficiency, low capital and non-fuel operating costs, and can be constructed more quickly and in relatively small economically sized units.

Over the past 20 years, natural gas's share of the electric power generation market shrank from 21.5 percent to 9.4 percent. This decline was largely due to:

- High gas prices in the late 1970s and early 1980s, and a belief in the 1970s that the nation was running out of natural gas, which prompted the passage of the Power Plant and Industrial Fuel Use Act. That Act, now largely repealed, restricted the use of natural gas.
- The construction and completion of large, baseload coal and nuclear units in the late 1970s and early 1980s. Coal's share of the generation market increased from 44.1 percent to 54.9 percent over the last 20 years and nuclear rose from 3.1 percent to 21.7 percent.

The potential for natural gas to have an increased role in the electric generation sector varies widely among sites (due, for instance, to the distance from a pipeline), applications, and companies. Positive influences toward increasing the demand for natural gas in the electric generation market include: Clean Air Act Amendments; substantial repeal of the Power Plant and Industrial Fuel Use Act; competitive gas prices; growing public opposition to coal-fired generation; environmental externalities favoring gas over alternative fuels; declining expectations for nuclear generation; concern over dependence upon imported oil; growing confidence in the adequacy of long-term gas supplies; and regulatory modifications to increase competition among companies in the gas industry.

NPC Reference Cases 1 and 2 suggest annual gas consumption for electric generation could increase to between 5.4 TCF and 4.9 TCF, respectively, by the year 2010. These increases are predicated on the assumption that the natural gas industry will be allowed to compete for the electric utility market on an equal basis with other generation options. A further key assumption behind any projection of gas penetration in the electric market is the annual electricity demand growth rate. If slower than assumed economic growth persists or electric demand side management activities accelerate, then the annual growth rate for electricity demand will likely fall below the 1.3 percent assumed in Reference Case 2, and increases in the demand for natural gas may consequently not materialize. Conversely, a more vigorous economic growth assumption can increase demand for electricity, and thus enhance the role of gas.

Opportunities for increasing the use of natural gas in electric generation include:

- Restarting existing gas-fired units or using gas-fired generating units at higher load factors
- Adding gas-burning capabilities in existing coal- and oil-fired units to gain fuel flexibility and/or meet environmental requirements
- Repowering existing generating facilities currently using oil or coal
- New gas-fired baseload, intermediate, or peaking units, built by traditional utilities or Independent Power Producers
- Commercial and industrial cogeneration and self-generation

- Repowering uncompleted or retired nuclear generating units.

Although significant opportunities exist for increasing the use of natural gas for electric generation, important challenges remain, including:

- Stiff competition from other energy sources, with wide variation among sites, applications, companies, distances from pipelines, and regions
- The need to understand factors affecting electric generators' fuel choices and to understand and respond to electric generators' concerns, needs, perceptions and expectations; in particular:
  - The need to satisfy potential customers that the delivered cost of natural gas, including the cost of gas transportation, will continue to be competitive with other energy sources and with potential demand-side measures
  - The need to satisfy potential natural gas customers that supplies will be available when needed and in the volumes and at the pressures required to meet variability in electric generation.

To deal with these challenges, it is recommended that the gas industry:

- Enhance its capability to analyze potential electric generation markets and take appropriate action to ensure that the people responsible for marketing gas supply, transportation, storage, or other services to electric generation customers understand clearly the factors affecting fuel choices, the economics of alternatives available to the customer and the customer's decision-making process.
- Recognize and address the perceptions and concerns of potential electric generation customers, particularly with respect to ensuring reliability of future gas supplies, dependable delivery of the supplies to customer's premises, and competitiveness of delivered gas prices with other alternatives.
- Work with individual electric generation customers to shape the terms and conditions of gas supply, transportation, and storage contracts to meet the particular needs of the customer.
- Increase its communications with the electric generation industry at all levels and find ways to work more cooperatively for the benefit of gas and electric customers.

Natural Gas Vehicles

There are an estimated thirty million fleet vehicles in the United States and over one-third of these are located in ozone non-attainment areas as defined by the Clean Air Act Amendments. U.S. fleet vehicles consume an equivalent of 2 TCF per year of liquid fuels. An increase in the number of dedicated natural gas vehicles (NGVs) will be necessary for gas to reach its full potential in the fleet market.

Natural gas is an environmentally and economically appealing fuel for urban fleet usage. Natural gas is the cleanest alternative fuel for internal combustion engines (vs., e.g., methanol, alcohol, and blends), generating 99 percent less carbon monoxide than gasoline.

In order for NGVs to penetrate the private vehicle market, several obstacles will have to be overcome. The American consumer will demand the same dependability, convenience, and flexibility as that afforded by gasoline powered vehicles. The fact that most natural gas vehicles currently in use are limited to a range of 100 to 200 miles suggests the advisability of increasing the number of accessible refueling facilities and/or increasing the range of the vehicles. The infrastructure to support NGVs is lacking. Currently, there are 530 private refueling stations located in the continental 48 states and less than 200 of these offer compressed natural gas (CNG) to the general public. This situation stems from the old "chicken and egg" problem, i.e., which comes first, the vehicles or the infrastructure? The industry needs to work with vehicle manufacturers and CNG suppliers to expand the infrastructure and the vehicle penetration.

Natural gas vehicles are currently exempted from road-use taxes. The industry needs to work with state governments to maintain equitable road-use tax treatment for all alternative-fueled vehicles.

For the purposes of the Reference Cases for this study, a modest penetration by the year

2010 was assumed. This results in a consumption rate of 140 BCF. A high penetration sensitivity case was run that projected fleet consumption to grow to 540 BCF in the year 2010 and the private passenger car market to grow to 100 BCF per year.

In the area of NGVs, it is recommended that the gas industry:

- Work together with the auto manufacturers to ensure that future NGVs provide the same dependability, convenience, flexibility, and range as gasoline vehicles.
- Provide adequate and accessible refueling facilities to the public where economically feasible.
- Become a leader in the use of NGVs in order to demonstrate the advantages of natural gas as a transportation fuel.

TECHNOLOGY

Effective natural gas research, development, and demonstration (RD&D) and commercialization are crucial to increasing the impact of new technologies. This study has concluded that the current collective natural gas RD&D activities are inadequate and commercialization is the weakest element. In order to improve its ability to commercialize new technologies, the gas industry needs to: (1) recognize the role of RD&D and provide adequate support; (2) become more market driven; (3) identify and satisfy the needs of the customers; and (4) convince regulatory agencies to support natural gas RD&D.

The technologies related to natural gas distribution and end use continue to evolve. However, efforts already underway are not sufficient for natural gas to reach its full potential in the nation's energy mix. Current research and development programs are inadequate. Even more serious is the history of feeble efforts at commercialization of successful RD&D results. Finally, there is simply insufficient funding of gas RD&D for major progress to be made in the frontier technologies. The major new markets for natural gas being explored are NGVs, commercial cooling, residential heat pumps, improved power generation, fuel cells, and selected commercial and industrial applications. Each of these applications may offer environmental benefits and generally tend to increase overall gas load factors. However, the high costs of developing, evaluating, and demonstrating these technologies are not met by current funding levels.

As discussed in Chapter Eight, 1992 investment in natural gas technologies is estimated to total $750 million. Of this amount, approximately $320 million (excluding Department of Defense expenditures) is dedicated to end-use and distribution technologies (with 92 percent of the total allocated to end uses). The sources of the funds are: distribution companies (14 percent), equipment manufacturers (31 percent), Gas Research Institute (30 percent), Department of Energy (25 percent), and other (1 percent). RD&D efforts need to be significantly increased through additional funding.

In the area of technology, it is recommended that the gas industry:

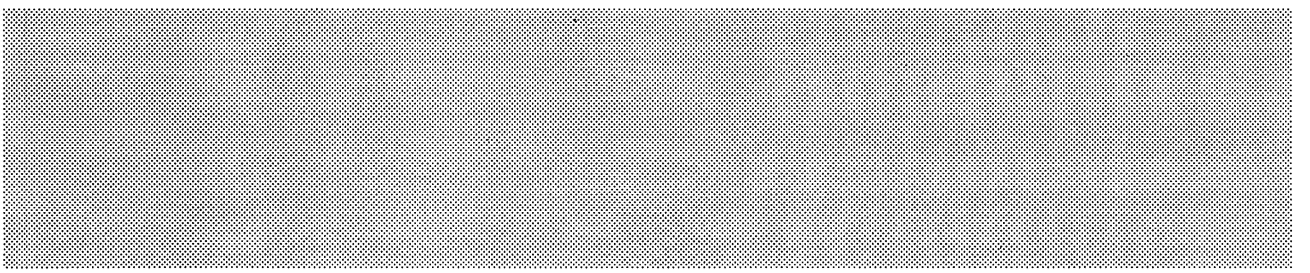
- Pursue federal government funding for a sustainable natural gas research, development, and demonstration program at a level of about $250 million per year to achieve the technology advancement necessary to allow natural gas to expend its contribution to the national energy mix. This level of funding is consistent with the supporting documentation of the recent National Energy Strategy and several recent studies, including those by the Washington Policy Analysis Group and the American Gas Association.
- Utilize natural gas for its own facilities, wherever economical, in order to demonstrate the benefits of natural gas to potential customers.
- Win regulatory support in the form of recovery through LDC rates for reasonable RD&D and commercialization expenses.

OVERALL DEMAND AND DISTRIBUTION RECOMMENDATIONS

An increased contribution of natural gas to the nation's energy supply can be accomplished by focusing efforts on the industrial, electric generation, and frontier technology markets, while at the same time improving services to the traditional core market, the residential and commercial customer classes.

In order to accomplish this, it is recommended that the gas industry:

- Identify individual customer needs, determine opportunities and risks, and develop the products and services to meet the customer's needs and maximize the provider's opportunities.
- Convince regulators to eliminate cross-subsidies between customer classes, where it exists, so that each customer class pays the appropriate cost of service.
- Promote the use of efficient gas technology by all of its customers to lower overall energy bills and thus make gas more competitive.
- Select people with appropriate marketing skills and background who are well equipped to fashion strategies to meet the needs of particular customers.
- Improve the marketing capability of its people within each sector by providing additional technical and sales training.
- Move from a regulatory-oriented approach to a customer-oriented vision by focusing on excellent service to all customers.
- Convince regulators to allow LDCs to recover through rates those prudently incurred marketing expenses that lead to additional throughput.
- Find a way for the various segments of the industry to speak with one voice on issues of common interest.



CHAPTER FIVE
TRANSMISSION AND STORAGE SYSTEM

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 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 5-1). 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 5-2 and 5-3). The cumulative investment

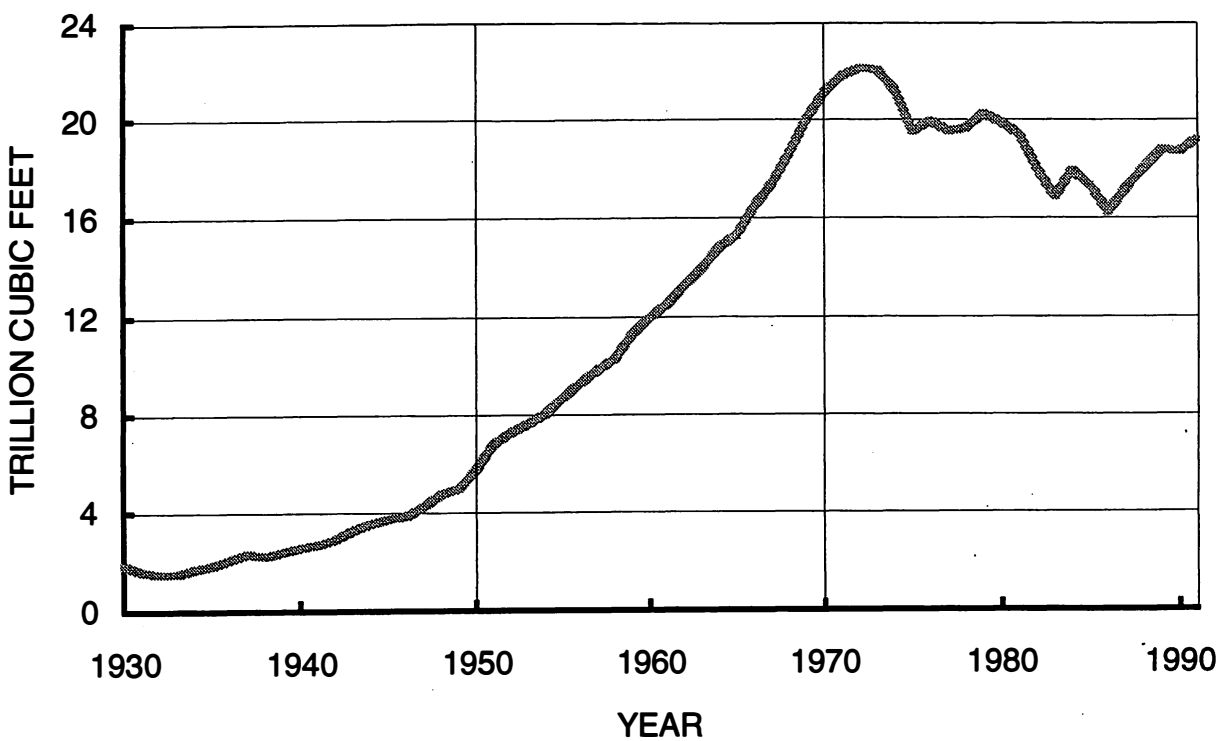
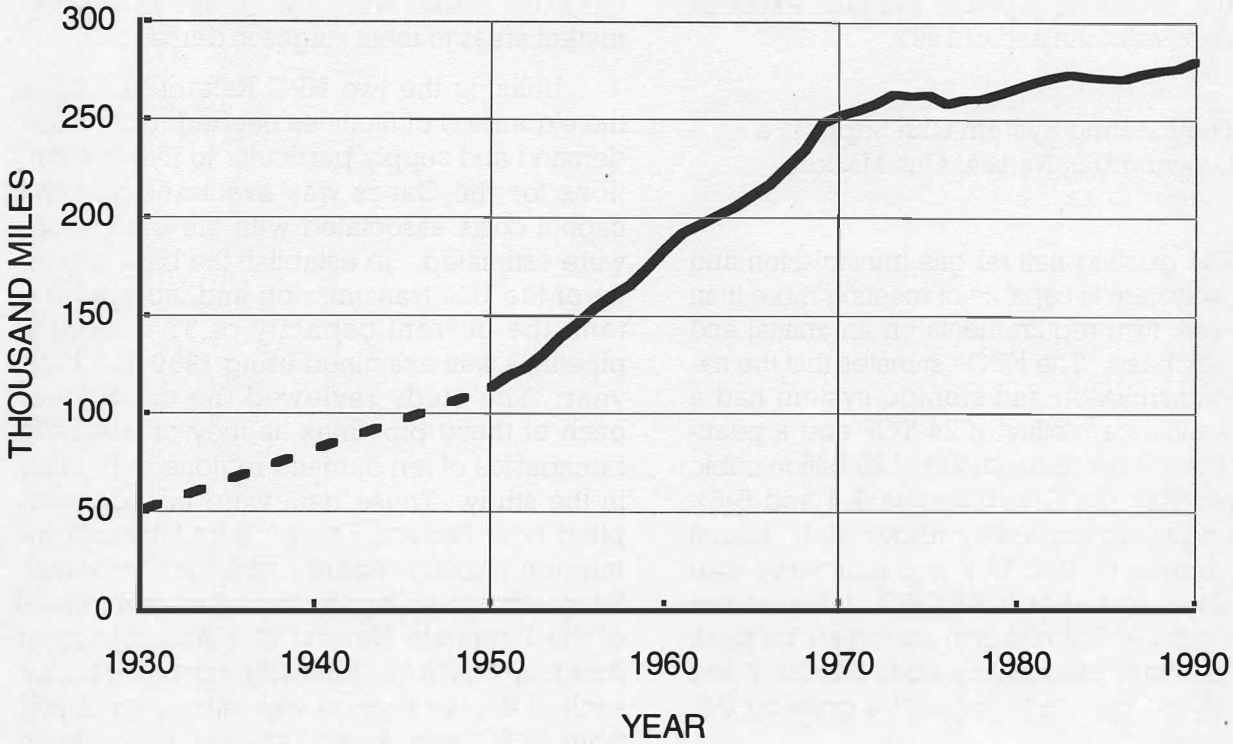
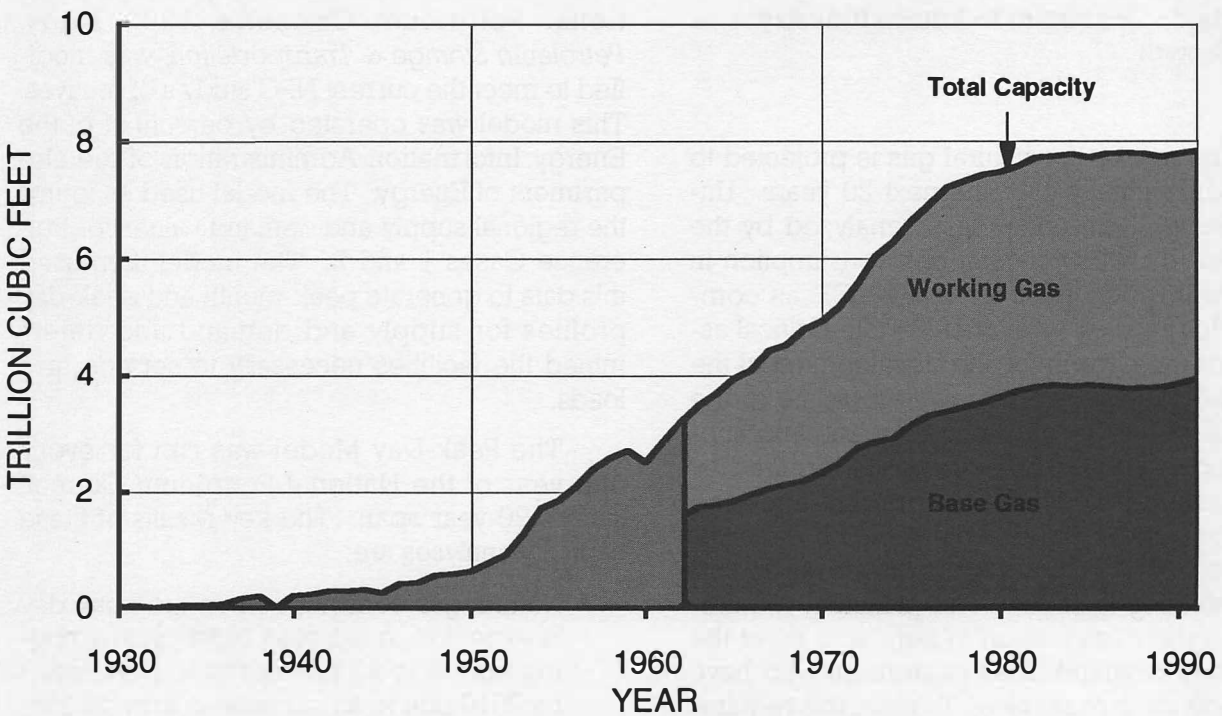


Figure 5-1. Total Natural Gas Consumption—1930-1991.



NOTE: Data prior to 1950 less reliable.

Figure 5-2. Miles of Natural Gas Transmission Line.



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

Figure 5-3. Underground Natural Gas Storage Capacity—1930-1991.

in 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 5-4 and 5-5). 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.

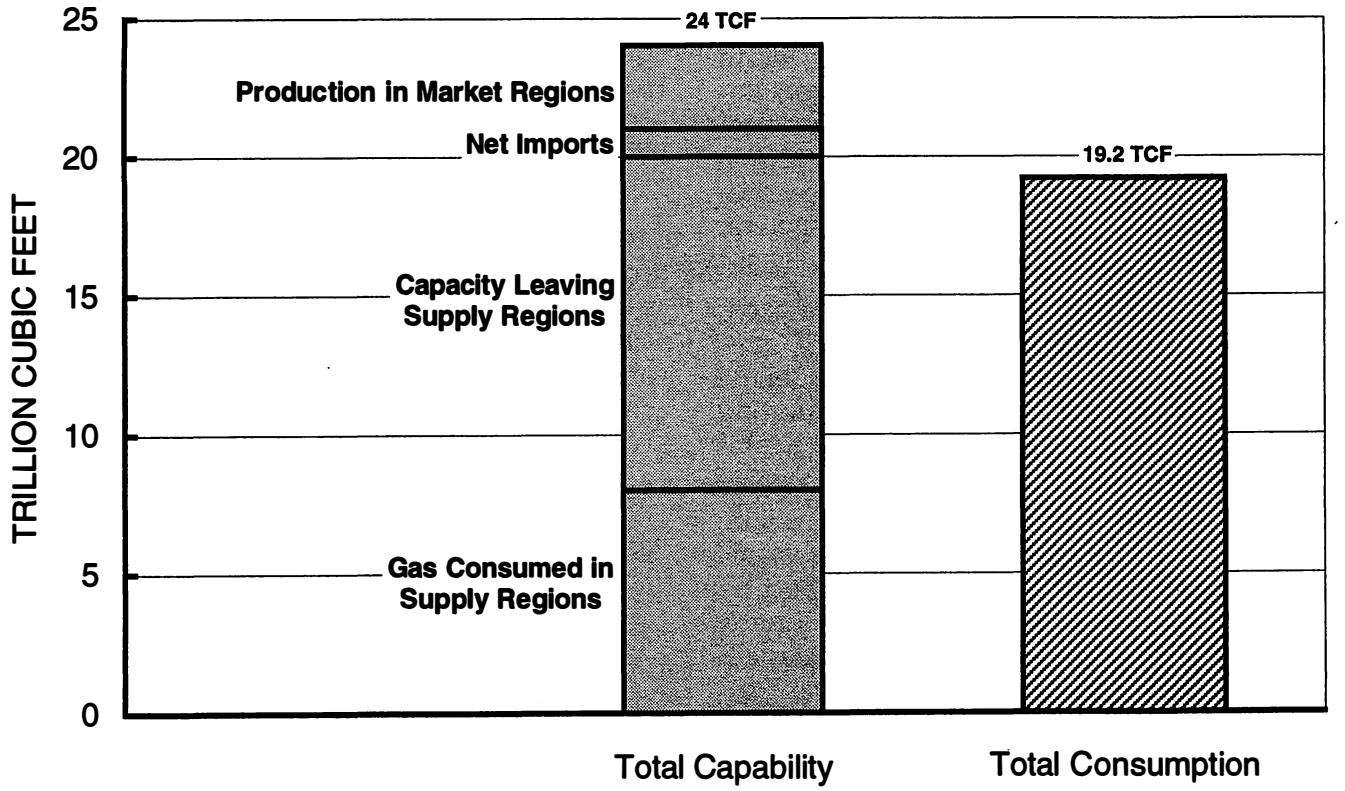


Figure 5-4. 1991 U.S. Transmission and Storage System—Annual Capability.

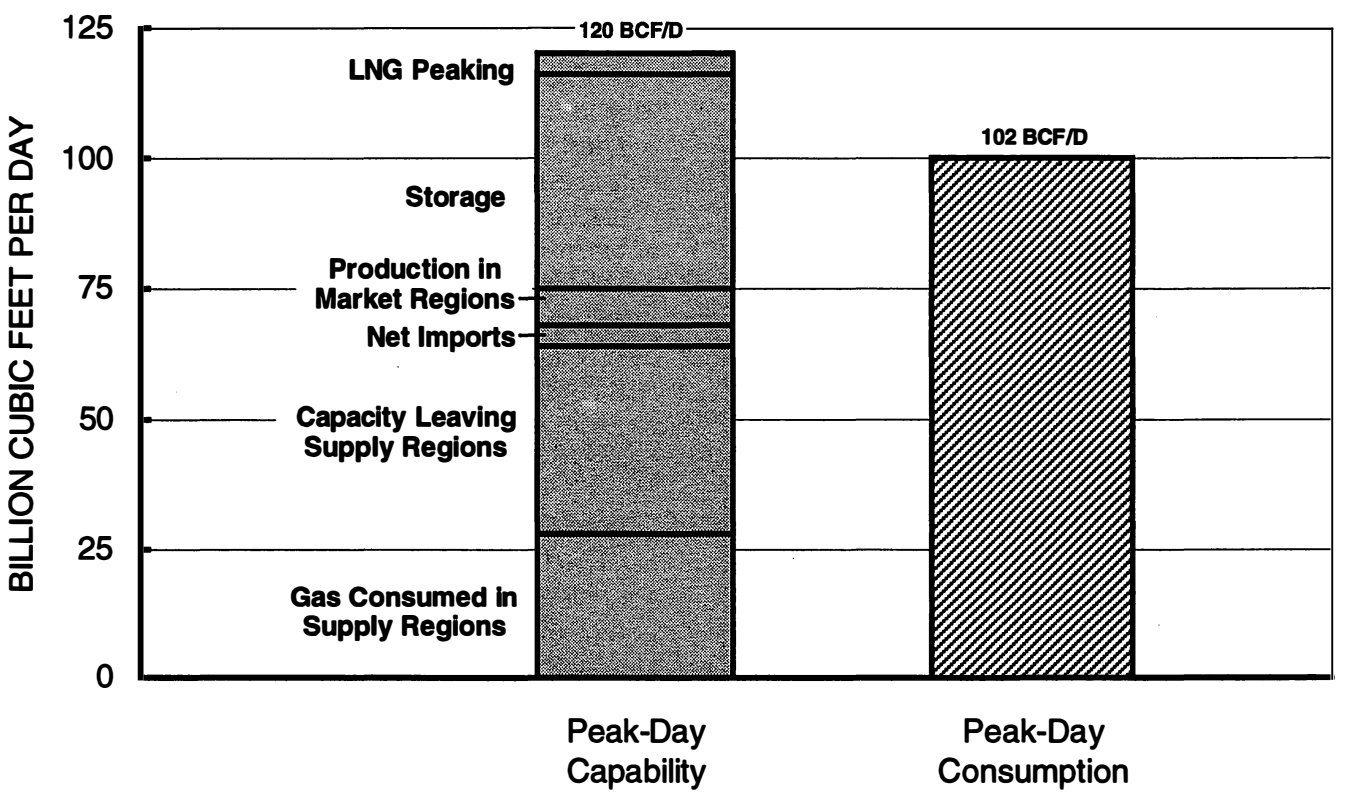


Figure 5-5. 1991 U.S. Transmission and Storage System—Peak-Day Capability.

- 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 Volume IV, Transmission and Storage.

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.

CHAPTER SIX
REGULATORY POLICY AND ENVIRONMENT

An abundant supply base, adequate delivery capacity, and unmet market needs portend bright prospects for growth of the natural gas industry. What regulatory and policy constraints could prevent our industry from achieving that growth? This question represented the starting point for this study's assessment of the regulatory and policy conditions facing the industry.

In order to assess the perceptions of the industry and its customers more accurately, the NPC sponsored a set of focus group sessions. The feedback from these sessions resonates in major themes and recommendations throughout the entire report.[1]

OVERVIEW AND CONTEXT

Major Themes: A More Business-Like Approach

In particular, four needs regarding regulation, policy, and behavior emerged as central regulatory and policy themes:

- Reduce regulatory uncertainty
- Reduce the traditional overreliance on regulation
- Stop behavior that leads to fragmentation and fractiousness within the industry
- Improve customer orientation.

Each theme emerges from an established industry history and culture. Dealing creatively with these challenges requires re-thinking some of our most ingrained beliefs.

Reduce Regulatory Uncertainty

For the past fifteen years, the natural gas industry and U.S. energy markets overall have undergone a fundamental transformation. The resulting regulatory structure has allowed competitive market forces to shape and develop a greater degree of customer-oriented natural gas services and pricing than in the past.

This evolutionary process has contributed to uncertainty about how regulation and competitive forces are likely to work in the natural gas market in the future. Unpredictable changes in the ground rules may alter the business context in which marketplace decisions are made. Regulatory risk borne of after-the-fact changes in regulatory requirements may in fact undermine the larger policy goal of changes intended to increase reliance on market forces.

As one focus group participant put it, "Things are changing so fast, you finally think you're starting to understand what the ground rules are and they change again." Customers perceive this regulatory uncertainty as an additional cost of buying natural

[1] The findings of the focus group sessions, as summarized by the consultant employed by the NPC, are presented in Appendix C of Volume V, Regulatory and Policy Issues. Critical review of this material is suggested, but the study does not necessarily endorse all of the specific conclusions made by the consultant in that document. Appendix D of Volume V provides information for those interested in obtaining copies of the reports of the individual focus group sessions.

gas. Therefore, reducing regulatory uncertainty is important to increasing the competitiveness of natural gas.

Halting regulatory reform is no solution to current problems of regulatory unpredictability, regulatory lags, and regulatory risks. Instead, regulators should advance changes that allow for more healthy, market-based competition where possible. Establishing the industry more firmly on a base of competitive transactions gives natural gas the best prospects for the future.

Regulation's role in the emerging industry must shift away from efforts to control markets and toward (1) assuring that adequate information is available to all customers and (2) policing the industry to prevent the abuse of market power. Making that shift quickly and clearly is the regulator's most important task.

In particular, clarity of vision on the part of regulators and effective communication of that vision are the best ways to reduce the uncertainty felt by many customers.

Overreliance on Regulation

As regulators struggle to allow competitive pressures to influence price and new service development, the gas industry's traditional overreliance on regulation and regulatory cues (or miscues) must also change. Industry participants must instead rely on their own business acumen and commercial business tools to define success in the markets. As one focus group participant related, "One utility president told me his customer is in the . . . capitol. And he was straight-faced." This kind of attention to regulatory influence broadly characterizes the natural gas industry—a consequence of many decades of heavy regulatory interference in markets.

As the pattern of natural gas regulation changes, the consequences of continued overreliance on regulation are increased regulatory uncertainty and a dangerous lack of customer focus.

Greater attention to competitive forces brings both opportunities and problems—but the problems can (and should) be managed creatively by those parties best suited to the job. A more flexible and competitive industry will naturally develop more services that are better designed to meet customer needs. Overreliance on regulatory signals will stifle the quantity and quality of new services that could flourish if market signals are allowed to replace regulatory cues.

Fragmentation and Fractiousness

All industry participants must work to end the fragmentation and fractiousness that have long characterized our industry. A strong sense of competition is natural, and even necessary, in the industry. Still, the *way* natural gas companies pursue competitiveness is important in creating a positive perspective of the industry.

As one focus group participant explained, "We spent a lot of time fighting the regulatory group in Washington. In so doing, we have made arguments that have been counter to what we should have been making to the customers." Future advantage will come not from victory in adversarial regulatory proceedings, but from customer-oriented efforts across industry segments to create natural gas services that economically and efficiently meet customer needs.

Many industry participants understand this need for change. The NPC study effort itself is an indication of changing attitudes. However, more must be done.

Customers interpret industry fragmentation, and the conflicting signals that arise from it, as evidence of unreliability. The industry needs, for example, more cooperative efforts to develop services designed for dispatchable power generators, to commercialize new gas cooling technologies, to invest in the infrastructure necessary to support natural gas vehicles. At the same time, the industry must develop better ways to meet the needs of our traditional customer base—residential, commercial, and industrial consumers—for reliable services at reasonable cost.

Increasingly, as companies see the value in these efforts, cooperative ventures will become the norm. Today, natural gas companies have the opportunity to begin to develop the relationships necessary to make that change happen.

Need to Improve Customer Orientation

Most importantly, the natural gas industry must improve responsiveness to customers. As one focus group participant explained it, " we have had to step back and try to figure out what it is that the customer wants. Not what we think the customer wants, but really finding what the hell the customers really want." Confusion regarding roles of industry players impedes this type of customer-oriented thinking. Such confusion is a natural consequence of changes in natural gas regulations and energy markets overall, but solving the "identity crisis" problems of industry participants must be a top priority.

Each company must listen to its customers to determine energy and service needs, alternatives, and business drivers. The services that add value to natural gas will have to fit customer needs better than alternatives. Success will depend on how the industry develops and markets these services.

Natural gas starts with the inherent advantage of being a clean, abundant, and efficient fuel. How this advantage is carried into the market will determine the natural gas industry's success in building the market.

Approach: A Vision Tested through Focus Groups

Without an overriding vision of the desired framework of the regulatory policy processes, individual constraints and their solutions are impossible to evaluate. Therefore, much effort was dedicated to developing a collective vision of regulation and policy. This vision allows for concrete comparisons of existing regulation and policy to a preferred condition.

In addition, and unlike the supply, demand, or transmission study areas, the regulatory process does not lend itself to readily quantifiable measurements. A different and fundamentally more qualitative methodology was dictated by this difference in the type of question posed.

To broaden and test the opinions and experience of study participants, a series of sixteen focus groups was initiated to build a "database" of views on the regulatory process and other key areas of concern in the study. Focus groups were held with producers, marketers, local distributors, industrials, electric utility fuel buyers, electric utility CEO's, independent power producers, state commissioners, state commission staffs, consumer advocates, cooling equipment manufacturers, gas industry equipment manufacturers, pipelines, financial institutions, and natural gas vehicle fleet operators.

Hypotheses were tested against focus group responses in order to document current industry conditions and perspectives, and to identify specific constraints posed by the existing regulatory system.

In summary, the approach was to reconcile the vision of the *desired* regulatory framework with the workings of the *current* system, as documented by the focus groups and the collective experience of the study participants. What lies between the vision and the existing system represents the true constraints, for which recommended policy and/or regulatory options are offered.

History and Context: Rigid Regulation Evolving Toward Reliance on Markets

The complex array of federal and state regulatory oversight which has grown up with the natural gas industry is unparalleled in our domestic economy. Directly or indirectly, this regulatory structure divides the pie of what has grown to be a $66 billion industry (in direct sales revenue, or about 1.2 percent of total Gross Domestic Product). Regulation also affects the flow of capital investment that determines the role of natural gas in the nation's energy future.

Historical federal regulation of natural gas viewed interstate pipelines as monopolies and put them at the center of a closely controlled, bundled natural gas business. Producers sold gas to pipelines, who in turn sold it to local distribution companies (LDCs), who in turn sold it to customers. The system sought to manage risk through long-term contractual and regulatory commitments and regulatory oversight.

Current state regulation of natural gas evolves from a long and troubled history of determined public interest protection in search of "just and reasonable" rates. This experience sits firmly within the context of broader public utility regulation concepts while attempting to

respond to the particular needs of the state's populace.

With the energy crisis of the 1970s, the combined framework of state and federal regulation that had evolved over the century proved to be poorly adapted to changing market conditions. Since then, the natural gas industry has undergone a series of fundamental structural changes, including widespread wellhead price deregulation in 1985, open-access transmission, and the unbundling of pipeline services. A structure of rigid regulation was replaced by a regulatory regime that relies in part on market forces and in part on the vestiges of price and service regulation.

In the 1990s, policy makers and regulators are continuing to make and implement decisions that foster competitive market dynamics and spur increasing reliance on contractual relationships and market-based price signals between the wellhead and the burnertip. *The natural gas industry's transition from regulated relationships to voluntary agreements between willing buyers and willing sellers is to be encouraged and facilitated.*

Despite this potential, the current mix of regulatory and market change has produced several glaring deficiencies in the industry. In the following section, we examine the constraints posed by this existing regulatory system.

REGULATORY CONSTRAINTS TO GROWTH

The focus group results, as well as the industry's collective experience over the past decade, point to numerous problems with the existing regulatory scheme. Ultimately, these may be described in terms of eight major constraints:

1. ***The regulatory process is unpredictable.*** Inherent unpredictability of regulatory decision making hampers successful natural gas marketing to energy markets that require any reasonable degree of certainty. Although some of this unpredictability arises from change itself, much of it arises from two other separate issues. First, regulators have often not been clear about the reasons for changes in regulatory practice. Second, changes in review methodology after-the-fact make straightforward commercial decision making difficult.
2. ***The regulatory process is slow.*** State and federal regulation has been slow to respond to fast-changing competitive market dynamics unleashed through (and sometimes in spite of) recent regulatory reforms. This lag in regulatory response creates market distortions by delaying or preventing market-based action. Compounding the problem, virtually inevitable court appeals stretch delays and attendant regulatory risks to intolerable levels.
3. ***The state and federal regulatory processes are uncoordinated.*** As natural gas passes from wellhead to burnertip, it is subjected to an uncoordinated stream of federal- and state-level regulation concerning subjects like proration, gathering, interstate, or intrastate pipeline rate making, and LDC regulation. Consumers and industry participants are often confused by the mixed signals they receive from these regulatory bodies. Overlapping and uncoordinated regulation increases costs to the industry and consumers alike, undermining the attractiveness of gas versus competing fuels.
4. ***The regulatory process distorts business decision making.*** By its very nature, natural gas regulation diverts the attention of regulated companies from promoting natural gas use. Focus group results indicate that, for natural gas, this tendency has reached an extreme where "distributor and pipeline executives are more concerned with meeting the needs of the regulators than they are the needs of customers." After-the-fact prudence reviews may distort business decisions like fuel procurement. Rate-of-return rate making, which may reward capital investment in rate base more highly than business-like decisions, encourages inefficient capital use by gas companies and biases electric utility fuel choice away from natural gas options. Regulatory risk/reward tradeoffs provide inadequate incentives for new pipeline capacity. Taken together, these distortions and disincentives prevent efficient use of management and assets to meet expanding market opportunities.

5. ***The regulatory process causes industry fragmentation.*** Producers, pipelines, marketers, distributors, and customers routinely find themselves in seemingly perpetual disputes before the Federal Energy Regulatory Commission (FERC) as well as 48 states' regulatory bodies. Parties often begin their battles before these agencies, continue the argument before Congress, and appeal not only to the courts, but even more often to the trade press. Current as well as potential markets are left viewing a divided industry with little credibility or appearance of reliability. Industry pays dearly for the *way* it competes.

6. ***Regulation limits customer choice.*** The nature of natural gas regulation has been to define and price a standard set of services from a sole supplier to a broad class of customers. This principle severely limits the effective marketing of natural gas products and services to niche markets with specific fuel needs and alternatives. The lack of meaningful incentives to provide enhanced, creative service options (and thereby better control costs and increase efficiency) thwarts increased use of natural gas.

7. ***Mixing rate making with social policy distorts natural gas markets.*** Rate making for regulated monopolies has become infused (and even confused) with social policy making. Historical economically inefficient cross-subsidies among customer classes have been justified on the basis of social policy. These decisions create additional costs for some or all customers. This indirect pursuit of social policy prevents efficient pricing, and it places natural gas at a competitive disadvantage versus unregulated energy alternatives (e.g., oil, coal, propane). Ironically, it may even ultimately prevent or discourage more direct and effective means of accomplishing the social goals intended.

8. ***The regulatory and policy environment implicitly treats natural gas as a scarce commodity and rewards existing customers or practices at the expense of new opportunities.*** Much state and federal regulation concerning natural gas assumes it is a scarce resource to be rationed among historical customers. As a result, traditional "high-priority" customers have received better quality service offerings than new "incremental" customers. "Incremental" markets, including power generation, industrial use, etc., have therefore been underserved. As a consequence, the resource base has been underdeveloped and, in the long term, historical customers are denied the benefits of an expanding market base.

The consequence of these constraints is a natural gas industry that cannot achieve the levels of supply and demand needed to produce the greatest efficiency and productivity. To fix these problems, regulators must help the industry move forward toward a more competitive, commercially driven future. The next section describes those recommended solutions.

SOLUTIONS

To better address the dilemmas facing today's natural gas industry, regulators and policy makers need to promote a clear, economically responsible regulatory vision, define the attendant standards, and implement the recommendations described below.

A Regulatory Vision

In the NPC's proposed new regulatory and policy model, increased reliance on competitive market dynamics supplants pervasive regulatory intervention as the preferred means of protecting and advancing the public interest. This vision's premise is the successful functioning of a competitive gas industry that provides a range of services and products to informed consumers who may choose the terms and prices that best meet their needs.

Thus, correspondingly, regulatory policy should be directed toward increasing the *number* and *quality* of choices available to buyers and sellers of energy goods and services, without unnecessarily interfering in the consequences of the choices buyers and sellers may exercise.

This vision emphasizes the role of competitive market principles, while recognizing a reduced role for regulation. Where market forces produce choices of adequate quantity and quality, regulatory policies should rely on those market forces. Where market forces exist, but

are not adequately developed to provide sufficient choices to consumers, regulatory policies should strengthen those market forces. Where market forces cannot produce adequate choices, regulatory policies should continue to protect consumers from exercise of market power by imposing a minimum level of choice on the industry, i.e., via the traditional "regulatory bargain."

This vision for the natural gas market incorporates business objectives of stability and profit opportunity based on commercial interaction, as well as regulatory objectives of ensuring customer choices in natural gas service while policing market power. A robustly competitive gas industry will, first and foremost, maximize consumer satisfaction. Implicit in the vision is an industry that will recognize and accommodate differing levels of risk tolerance among segments of the gas industry and its consumers. Risks and associated costs will then be managed by the most capable party.

Under this competitive vision, regulators need to step back and allow customers to decide freely their own levels of service and risk tolerance. Those customers will then bear the costs or reap the savings associated with their choices. Because the functioning of individual choice is integral to achieving the public interest, regulators should not usurp or forestall customer choices by substituting their opinion of risk tolerance for that of the customer.

New Standards for Natural Gas Regulation

The standards that emerge from our vision of natural gas regulation are summarized and contrasted in Table 6-1 with the widely adopted (or perceived) existing standards.

Two conclusions must be drawn from this side-to-side comparison. First, the new standards are a radical departure from the existing model of regulation. Having let the genie of competition out of the bottle, the efficiencies of competitive markets will be severely distorted without a near complete overhaul of the existing model. Second, the new standards involve policy trade-offs between government's former role in controlling industry and its future role in encouraging industry to develop new services.

In adopting new standards, the industry will take strides toward further deregulation. Nonetheless, this standard deliberately stops

TABLE 6-1

NEW STANDARDS FOR NATURAL GAS REGULATION

Existing Model	Recommended Model
Just and Reasonable	Competitive
Prudent	Responsive (To Shareholders & Customers)
Cost Based	Market Based
Social Policy Influenced	Neutral
Protection	Choice (And Risk)
Tariffs	Products
Regulatory Uncertainty	Observable Market Risks
Penalties	Incentives
Stability	Efficiency
Adequate Supply	Contractual Security
Lowest Reasonable Cost	Market Cost
Guarantee	Opportunity
Reliability	Service
Franchise	Market Focus

short of recommending complete deregulation. It recognizes that natural monopolies persist in some sectors and may preclude direct competition from producing an economically efficient outcome. However, it also recognizes that the bundled natural gas services of the past have distorted the nature of existing natural monopolies. For example, natural gas resales are no longer a natural monopoly, although, in many cases, natural gas transportation or distribution remains a natural monopoly. These important distinctions must be made explicitly.

As a practical matter, and despite apparent efficiency costs, some form of continuing regulation is necessary at both the federal and state level. That regulation should police markets for exercise of market power. Regulation should no longer control those markets for policy purposes.

Recommendations

Accordingly, this study's regulatory and policy recommendations, separated into categories of general, federal, and state applicability, are designed to move the industry toward the vision that best meets the goal of allowing natural gas use to grow to its economically efficient level.

General Recommendations

The following recommendations apply broadly to both FERC and state regulatory agencies.

Public Interest Definition

Policy makers and regulators should redefine the public interest pursued in their policies, consistent with the following:

- The objectives that govern the natural gas regulatory process should be reviewed anew, and should include a clear identification of the public interest being furthered.
- Regulatory objectives should be the result of a coordinated state and federal agreement on a new definition of "public interest."
- The public interest should be defined in terms of a functional, competitive gas industry that provides a range of products and services to informed consumers who may choose the terms and prices that best meet their respective needs.
- Industry participants as well as consumers must work with regulators to develop a new regime consistent with revised "public interest" goals.

Regulatory Philosophy

Regulators should enunciate and act upon a regulatory philosophy consistent with the redefined public interest.

- Regulators should affirm the use of market forces in lieu of regulation where such forces are sufficiently robust to provide the market with reasonable service choices.
- Regulation should refrain from unnecessarily restricting the number or quality of choices made available to the buyers and sellers of energy services; neither should it interfere with the consequences of those choices.
- Cross-subsidies among customer classes should be phased out.

Use of Competition

Regulators should identify competitive markets and consider alternative rate structures.

- Regulatory decision making should defer to market forces where they are sufficient to meet customers' needs for choice among economic, efficient, and reliable services.
- Phased activities and pilot projects should be used actively to explore the feasibility of new regulatory structures that use competition in place of traditional regulatory control.
- For markets in which meaningful competition does not exist and where adequate safeguards can be developed, regulators should explore the potential value of incentive rate making. Rate ceilings should be emphasized over profit ceilings. Where continued regulatory oversight is required, pilot projects should be adopted to develop regulatory and industry experience en route to more wide scale programs. Potential examples

include sharing-of-savings mechanisms and flexible rate authority.

- Gas procurement should be deregulated where appropriate competitive markets are determined to exist and buyers have meaningful equal access to competing gas supplies.
- Regulation of safety and related minimum service standards should remain intact.

Communication

Regulators should invite meaningful communication with each segment of the industry, and across regulatory jurisdictions, with regard to general policy and rate issues.

- Communication should take place individually and through regulatory and industry associations.
- Regulators should attempt to understand the effects of their regulatory decisions on sectors of the industry, in order to prevent undesirable side-effects, and for consistency with overall national policy objectives.
- The FERC should clarify its interpretation of *ex parte* rules to recognize the importance of effective communication in the context of generic rule makings.
- Congress should modify the Sunshine Act so that it does not apply to generic proceedings.
- Federal and state regulators should be encouraged to meet in order to discuss general regulatory issues and objectives.

Regulatory Certainty

Regulators should develop procedures that improve regulatory predictability.

- Individual rules and regulations, as well as authorizing statutes, must be reviewed to remove impediments to real-time informed choices and educated risk assumptions by natural gas sellers, transporters, and customers.
- Regulatory proceedings that remain necessary must be timely and efficient. Procedures should be adopted so that no rate case at the state or federal level would take longer than a reasonable time certain, such as nine months.
- Adequate staff and resources to perform timely regulatory functions should be sufficiently budgeted.

Specific Federal Recommendations

New Construction Test

The FERC should eliminate the traditional tests for new interstate pipeline construction:

- The historical test of sufficient supply backed up by long-term contracts and attendant firm service agreements should be eliminated.
- Parties should be permitted to allocate risk through contractual mechanisms.

Up-Front Rate Treatment

The FERC should provide determinations of the rate treatment for new facilities in advance of construction.

- Both project sponsor and affected customers must be afforded reasonable predictability in regulatory rate treatment before construction commences.

Secondary Markets

The FERC should continue to promote the development of robust secondary markets for regulated transport services. Customers should be allowed to trade capacity rights in minimally regulated secondary markets.

Define Competition

The FERC should continue its efforts to establish a definition of competitive markets for transportation and other services.

Specific State Recommendations

LDC Unbundling

State commissioners should evaluate and direct as appropriate the unbundling of LDC sales and transmission services to further the general pro-competition and pro-consumer objectives of the National Energy Strategy and FERC Order 636.

Uniform Code

To promote consistency in state regulation, an appropriate body, such as the National

Association of Regulatory Utility Commissioners, the National Association of State Legislators, or the National Governor's Association, should investigate the establishment of a uniform code of regulation available to all state jurisdictions.

Integrated Energy Resource Planning

State regulators should adopt a fully integrated approach to energy resource planning.

- Environmental advantages of natural gas should be recognized in total energy resource planning.
- Evaluation of natural gas applications in meeting traditional end-use markets for electricity (e.g., gas cooling) should proceed in tandem with evaluation of alternative electric integrated resource planning solutions.

Re-evaluation of Franchise Protection

The benefits of and need for franchise protection for LDC services should be reviewed and re-evaluated.

- State regulators should distinguish between captive and non-captive customers and should explore alternatives to traditional service obligations where competitive markets exist or can be created.
- Access to multiple supply options for all customers should be encouraged.
- Regulatory policy should provide LDCs with the appropriate cost allocation, rate design, and pricing flexibility to enable LDCs to compete in the marketplace so that regulators do not have to promote or prohibit bypass of local distributors.

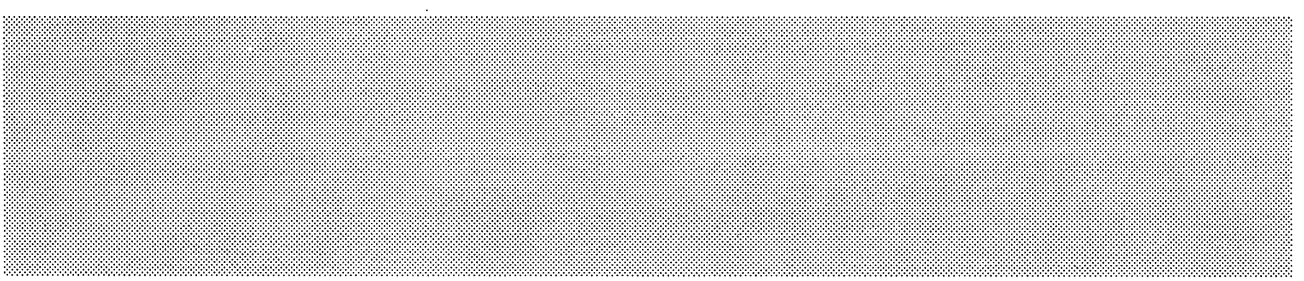
Proration Policy

States should continue to protect the correlative mineral rights of producers and royalty owners and to prevent physical waste through proration rules.

- Limitations on production to protect correlative rights and to prevent physical waste should be divorced from any efforts to control supply or to raise the wellhead prices of gas.
- Producers should be left with the maximum possible discretion to manage their production in relation to swings in market demand and prices.

Define Competition

State regulatory commissions should establish task forces to define and identify competitive markets for transportation and distribution services.



CHAPTER SEVEN
ENVIRONMENT

OVERVIEW

Just as natural gas plays an important role in meeting the nation's energy needs, environmental and access issues play an important role in the natural gas industry's ability to bring clean-burning natural gas to its customers. The actual impact of environmental issues on the natural gas industry is in many ways a dichotomy. On the exploration, production, transportation, and storage sectors of the business, where companies are faced with increasing costs for environmental controls and growing permitting and access restrictions, environmental issues work against the industry's ability to supply natural gas to the end user at a competitive price. However, on the downstream or end-use side of the business, environmental issues actually create an incentive. If natural gas can be delivered at a competitive price, its clean burning characteristics can help meet the growing environmental needs of the industry's consumers and the nation.

The purpose of the environmental section of this report is to examine the environmental dichotomy and develop recommendations for the Secretary of Energy, and the natural gas industry, that will help develop natural gas as an important contributor in the National Energy Strategy. On the exploration and production side of the study, Volume II, Source and Supply, rigorously identifies and quantifies the potential impact of environmental regulations and access issues on the exploration and production of natural gas. Volume IV, Transmission and Storage, identifies the impacts of environmental regulations and permitting restrictions on the transportation portion of the industry. On the end-use side of the study, Volume III, Demand and Distribution, identifies not only the environmental impacts, but also the environmental advantages of natural gas for the end-use customer. The ultimate goal is to define actions for both government and industry that will eliminate or reduce the environmental dichotomy surrounding the production and use of natural gas; to create a balance in national environmental policy that fairly and accurately weighs upstream environmental regulations against the downstream benefits of using natural gas as a clean burning fuel.

Summary of Findings and Recommendations

The NPC has examined the impacts of potential future environmental regulations and access limitations on the exploration and production (E&P) and transportation and storage of natural gas. The results of this analysis demonstrate a clear potential to limit the ability of industry to increase the production of natural gas as an important resource in the national energy strategy. On the downstream or end-use sector, there remain unfulfilled opportunities to increase the use of natural gas driven by environmental regulations aimed at solving the nation's air quality problems. Within this apparent dichotomy, *the challenge* is for industry and government to work together to solve the pressing environmental issues facing the E&P and transportation sectors in a balanced and

cost-effective manner. *The opportunity* is for industry to maximize its potential to develop new environmental markets. The rewards are sustained growth for the industry and improved air quality for the nation.

The following are general recommendations from the study designed to meet the environmental challenges and take advantage of the environmental opportunities. More detail on these recommendations can be found at the end of this chapter and in the subsequent volumes of this report.

General Recommendations

Recommendations for Government

1. Encourage government, at all levels, to create a balance between costs and benefits in the legislative and regulatory process for environmental and access issues that effect the natural gas industry (i.e., exploration and production, transmission, and consumers). This includes the direct recognition of the environmental benefits of natural gas as a fuel.

Recommendations for Industry

1. Develop and supply timely and credible technical cost-benefit data for use in communication efforts with government, other industry groups, environmental groups, and the general public. Focus research activities toward developing more cost-effective technical solutions to the environmental challenges facing the natural gas industry.
2. Enhance education programs to increase the public's understanding of the positive role natural gas can play in solving the nation's environmental problems. Target audiences include federal, state, and local governments, other industry groups, environmental organizations, and the general public.
3. Develop new technology and innovative industry strategies to better align the natural gas industry's goals with the public's needs and expectations in order to expand markets and create more timely and efficient solutions to environmental, permitting, and access issues. Create win/win situations for the natural gas industry, its customers; federal, state, and local governments; environmental groups; and the general public.

EVOLUTION OF THE ENVIRONMENTAL MOVEMENT

The Environmental Movement—Its Goals, Policies, and Politics

By the 1960s, a growing concern for water, air, and natural lands of the United States was growing into an awareness that uncontrolled discharges and emissions, urban and industrial growth, and development of, and reliance on, chemicals were taking a toll on the natural environment. Rachel Carson's *Silent Spring* documented the unintended effects of DDT and other pesticides on wildlife, particularly birds. In addition, there was a growing recognition that air quality had badly deteriorated in many cities, that many of the nation's major surface waters had severely deteriorated, and that our living spaces were encroaching on our natural surroundings. Esoteric terms like "environment" and "ecology" started as cult themes and then grew into a movement. An electorate outraged by environmental accidents and revelations like the Santa Barbara Channel oil spill, the Cayahoga River fire, the Love Canal toxic waste dump, and the Three Mile Island nuclear reactor incident prompted waves of new federal and state laws to address pollution problems, real or perceived.

Following these environmental alarms, environmental policy and regulation developed a patchwork of overlaps and gaps. Statutes and regulation were designed to deal with specific problems, rather than being part of a comprehensive scheme.

Over the past decades a system of statutes, regulation, guidelines, factual conclusions, and case specific interpretations has evolved. The individual elements, however, do not work together to achieve the system's objectives. This system is made ever more daunting by the uncertainties and the complexities of the scientific issues always encountered in environmental cases.

The Nature of Regulatory Approaches

Most regulatory systems develop characteristic sets of duties and compliance require-

ments adapted to the subject matter and circumstances being regulated. The environmental statutes and regulations are no exception to this rule. There are about eight generic obligation or regulatory approaches, all affecting the gas industry, that are utilized in some combination by virtually all environmental laws.

- ***Notification Requirements***—To advise appropriate authorities, employees, and the public of intended or actual releases of pollutants, violation of discharge limits, or other prohibition and of the commencement of activities, such as resource extraction or construction, which may have significant environmental impacts.
- ***Point of Discharge or "Waste End" Controls***—Also referred to as "Command and Control," to prevent or acceptably minimize the release of pollutants into the environment.
- ***Product-Oriented Controls***—To ensure that products are designed, formulated, packaged, or used so that they themselves do not present unreasonable risks to human health or the environment when either used or disposed of.
- ***Process-Oriented Controls and Pollution Prevention***—To reduce the quantities, prevent the release, and minimize the hazardous characteristic of wastes that are generated.
- ***Regulation of Activities***—To protect resources, species, or ecological amenities.
- ***Safe Transportation Requirements***—To acceptably minimize the risks inherent in transportation of hazardous wastes or materials, oil, gas, or other potentially harmful substances.
- ***Response and Remediation Requirements***—To reduce the threat of release or clean up pollutants that have been released.
- ***Compensation Requirements***—To make responsible parties pay for damages done to the health or environment or to permit self-appointed representatives of the "public interest" to recover for injuries done to public assets.

ENVIRONMENTAL CONSTRAINTS AND IMPACTS ON THE NATURAL GAS INDUSTRY

Background

In each natural gas industry sector, from wellhead to burnertip, there are environmental requirements that ultimately affect the cost and availability of gas to the nation. If natural gas is to have a role in the national energy policy and a role in helping reach national environmental goals, then decision makers must ensure that the costs of compliance with environmental laws and regulations are commensurate with the benefits achieved, and in line with these national policies and goals. This section describes the effects of current environmental policies on the cost, supply, and availability of natural gas.

Since natural gas has intrinsic environmental benefits as a clean-burning fuel, the study began with the premise that there is a set of "Constraints" that exist, that prevent or inhibit the full utilization of natural gas in the national energy strategy. These "Constraints" exist both external to the industry (i.e., legislative, regulatory, etc.) as well as internal to the industry (cultural, policy, practices, etc.). The methodology employed by the group included facilitated brainstorming sessions, E&P sector modeling to estimate the potential impact on supply, regional demand analyses, and focus group discussions. These methodologies drew on the combined expertise of the industry and government members of the study teams, key representatives from other interested members of the study, members of the regulating community, and end-use customers. The process produced the following observations regarding the environmental "Constraints" facing the industry along with a corresponding series of "Options" (i.e., Recommendations) available to government and industry to overcome these "Constraints." These "Constraints" are discussed below by industry segment. The Recommendations to overcome these "Constraints" are discussed at the end of this chapter.

Why Environmental Constraints Exist

A number of problems exist that constrain the full utilization of natural gas. These problems include less than optimum government policies, processes, and practices (legislative, regulatory, and administrative); misperceptions

and misunderstandings about the natural gas industry and its practices by government and the public at large; superior strategy by environmental groups; and the lack of a coordinated and cohesive industry process to understand and meet the environmental needs and expectations of the public. These issues are discussed in more detail in the section on Public Policy and Perception Issues.

Summary of Constraints

The environmental legislative and regulatory decision making process in the United States, coupled with the industry's currently inward-focused culture, inhibits the full utilization of natural gas, as an environmentally preferred fuel in the national energy mix. A summary of general constraints include:

- Legislation, regulation, and government policy does not adequately balance the direct upstream costs and benefits of regulations and does not include an analysis of the downstream benefits of natural gas.
- The environmental benefits of using natural gas are not well understood by the public and policy makers. The natural gas industry is seen more negatively than deserved and is perceived as not being credible and is not trusted.
- Environmental interest groups operate with a high level of public trust and they, along with competing industries, have been more successful in focusing their resources in an effective advocacy strategy.
- The natural gas industry has not been successful in fully aligning its goals with the public's needs and expectations.

The end result has been an increasing economic burden from environmental regulations relative to benefits, drilling moratoria, the cancellation or deferral of government lease sales, lack of access for exploration, production, and pipeline right-of-ways, and federal and state legislative and regulatory policies that inhibit the use of natural gas.

Environmental Constraints on Exploration and Production

Volume II, Source and Supply, examines the impacts of potential future environmental regulations and access limitations on the exploration and production of natural gas. The results of this analysis demonstrate a clear potential to limit the ability of industry to increase the production of natural gas as an important resource in the national energy strategy. In addition, these same environmental regulations also have the potential to reduce the role that natural gas can play in solving the nation's air quality problem. Within this apparent dichotomy, the challenge is for industry and government to work together to solve the pressing environmental issues facing the E&P sector in a balanced and cost-effective manner, the opportunity is sustained industry growth and improved air quality.

The methodology used to quantify these challenges and opportunities included:

1. Developing two environmental cases to characterize the range of plausible future environmental regulation for the purposes of modeling a range of potential future economic impacts.
   - ***Reference Case:*** A level of environmental regulation adequate to protect human health and the environment, while balancing the costs and benefits of environmental regulations and recognizing the value of domestic natural gas production and end use. The analysis included a quantitative evaluation of the financial impact of potential additional future regulations, based upon a qualitative assessment of the level of regulation required to achieve environmental and economic balance. The result is reference case assumptions of compliance costs substantially above current requirements.
   - ***High Environmental Regulation Sensitivity Case:*** The philosophy of this sensitivity case assumes that national policy will continue to press for increased environmental protection, at ever increasing costs, for the foreseeable future. Thus, natural gas E&P activities will be subject to increasing levels of environmental regulation (a high economic impact case). Again the analysis included a quantitative evaluation of the financial impact of potential additional future

regulations based upon a qualitative assessment of the level of regulation.

2. Developing cost estimates for compliance with anticipated regulations under the new Clean Air Act Amendments, the Safe Drinking Water Act, and pending Resource Conservation and Recovery Act and Clean Water Act reauthorizations
3. Modeling the impacts of the High Environmental Regulation Sensitivity Case assumptions on both of the NPC Reference Cases using the Hydrocarbon Supply Model.

Environmental Requirements

In developing this report, a wide range of environmental laws that affect or may affect the domestic natural gas E&P industry were examined. Some of the laws and regulations have specific requirements for which it is possible to develop compliance costs. These laws, regulations, and related environmental initiatives were used in the Hydrocarbon Supply Model to examine the effect of environmental requirements on compliance costs, the resource base, and natural gas E&P activity. This section of the report briefly describes the laws used in the model, their requirements, and how they affect natural gas production. Many other laws and regulations are not as direct or predictable in how they affect the cost of producing natural gas or how they may affect industry's ability to access prospective acreage. These laws are discussed in more detail in Volume II, Source and Supply.

Major Laws Used in the Model Impacting Exploration and Production

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act of 1976 (RCRA) was the first federal attempt to address the management of solid and hazardous wastes and to promote conservation through waste recycling. Subtitle C of the Act is designed to provide cradle-to-grave management for hazardous waste generation, storage, transportation, treatment, and disposal. Subtitle D provides federal guidance to states in regulating non-hazardous wastes. Amendments to RCRA in 1984 added regulation of petroleum and hazardous wastes stored in underground tanks.

Congress exempted wastes associated with oil and gas operations from being categorized as hazardous wastes, subject to the Environmental Protection Agency (EPA) review of the need for regulating these wastes. A 1987 EPA report concluded that high volume, low toxicity oil and gas wastes did not need to be regulated under Subtitle C. Most of these wastes are regulated by individual states.

Future legislation may change how oil and gas wastes are treated. Reauthorization of RCRA may affect disposal of drilling muds and cuttings, the use of pits at drilling and production sites, and remedial clean up of oil drilling sites. Of all the environmental regulations considered, RCRA has the greatest potential for increasing compliance costs on E&P operations.

Clean Water Act

Passed as the Federal Water Pollution Control Act of 1972, this statute's objective is to restore and maintain the chemical, physical, and biological integrity of the nation's waters. As amended in 1977 (which changed the name to Clean Water Act [CWA]), the CWA establishes a system of effluent standards by industrial category, provides for a permitting system, sets waste water quality standards, provides for grants for municipal waste treatment, and addresses special issues like toxic wastes and oil spills. The authority for wetlands protection is contained in Section 404 of the CWA, to be discussed in a later section. The CWA is scheduled to be reauthorized.

The effluent limitation standards and the National Pollutant Discharge Elimination System (NPDES) permit program are the chief regulatory tools under the authority of CWA. Effluent limitations are based on what is technologically achievable, not necessarily on the environmental benefit realized. Most of the effect of the CWA on natural gas E&P results from the NPDES program on offshore drilling and production.

Clean Air Act

The first federal Clean Air Act (CAA), passed in 1967, established air quality standards, but the CAA of 1970 established a more comprehensive federal-state partnership for air pollution control. Health-based and general welfare-based ambient air quality standards are

set at the federal level and states develop implementation plans to attain and maintain those standards. Though amended in 1977, the CAA amendments of 1990 add tough new measures for ozone non-attainment areas, provide for reduction of acid forming emissions, tighten up on mobile source emissions through controls and alternative fuels, set up a comprehensive permitting program, and create emission control standards for a new list of toxic emissions.

Natural gas E&P will be affected by temporary emission control requirements, which may restrict construction and drilling emissions, and long-term emission control requirements for new, modified, or existing facilities (i.e., fugitive hydrocarbon emissions from field operations and gas plants). In areas that are not in attainment of ambient air quality standards, emission offsets may also need to be acquired.

Safe Drinking Water Act

The Safe Drinking Water Act of 1984 (SDWA) established the Underground Injection Control (UIC) program to protect drinking water aquifers from contamination by subsurface injection of fluids. The Act required the EPA to establish minimum requirements for state programs or for federal primacy in the absence of state programs.

The UIC affects all underground injection associated with oil and gas exploration and production activities. Natural gas E&P may be affected by requirements for mechanical integrity testing of produced water injection wells. If fresh water aquifers are not being protected, then action may be required to correct the situation.

Laws Affecting Access Used in the Model

The following laws were used in the model to add compliance costs (Wetlands Protection) or were used in determining when resources in a hydrocarbon region would be available (OCS Moratoria). Both these laws are also discussed in the Emerging Environmental Issues section because they add unspecified costs and affect access.

Wetlands Protection

The authorities to protect wetlands come from the River and Harbors Act of 1899 and the CWA and cover both public and private lands. Though not clearly codified, the national policy of no net loss of wetlands can force activities to be restricted from, or severely modified within, a wetland area. The broadened definition of wetlands extends this protection to more areas.

Natural gas E&P activities may be forced to relocate to protect the wetland, and/or to mitigate impacts through replacement, enhancement, or creation of wetlands.

OCS Moratoria

Although the OCS program is administered by the Department of the Interior (DOI), since 1982 Congress has added language to the DOI budget appropriation every year placing certain offshore areas under leasing moratoria. Each appropriations statute has blocked leasing in the affected offshore area for one year. Beginning in 1984, Congress began blocking exploration activity on existing leases through the appropriations process.

Impact on Cost and Supply

The following are highlights of the cost and supply impacts that occur over the 20 year study period using NPC Reference Case 1 (the moderate economic growth case) as an example [results for NPC Reference Case 2 (the low economic growth case) are generally similar]. The two modeling results that best characterize the impacts of potential future environmental regulations on the ability of the E&P sector to explore for and produce natural gas are "total compliance costs" and "the impact on production volumes." Each of these indicators is briefly described below.

Figure 7-1 shows the environmental compliance costs in 1990$ for both Reference Case 1 and the High Environmental Regulation Sensitivity Case. The annual compliance costs reach over $3.5 billion in the high sensitivity case, whereas they are less than $750 million in Reference Case 1. The cumulative compliance costs for industry for the 1992-2010 period under the reference case totals $12 billion, while under the sensitivity case, the cumulative total equals $47 billion. It is important to point out that even Case 1 represents roughly a 10 percent increase in new well costs onshore in the lower-48 states above today's already carefully controlled and monitored operations. This

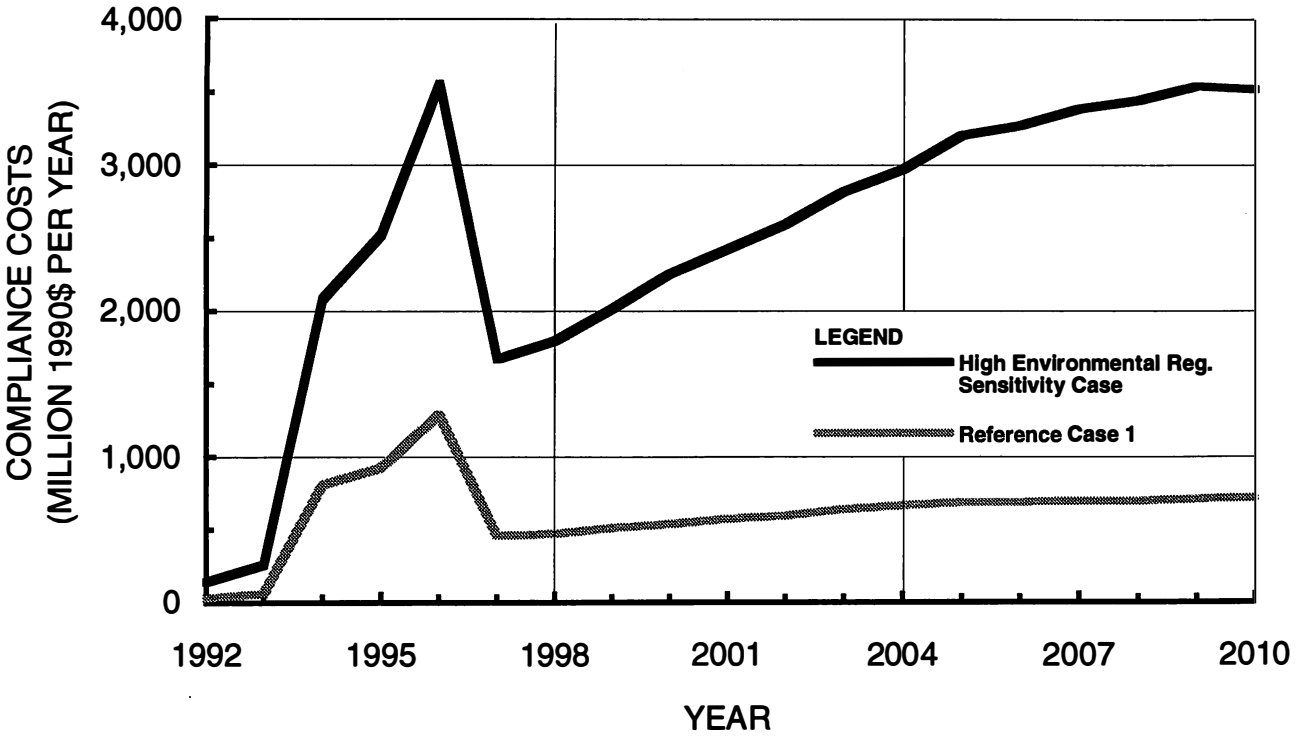


Figure 7-1. Lower-48 U.S. Natural Gas Exploration & Production Environmental Regulation Compliance Costs.

expenditure growth translates into a trend only slightly below the historical rate of industry environmental expenditures.

Using the reserve impact modeling approach described in Volume II, the production volumes for the lower-48 states are shown in Figure 7-2 for both Reference Case 1 and the High Environmental Regulation Sensitivity Case. Note that the difference between environmental scenarios, or the net decrease in production due to higher compliance costs, is nearly 2 TCF per year by 2010 with a cumulative reduction from 1992-2010 of over 17 TCF. It should also be noted that the decrease in production increases throughout the period as existing production declines and new discoveries and infill development drilling play a larger role in the supply forecast.

As a brief summary, the following impacts represent the incremental costs and effects of the sensitivity case over Reference Case 1 and demonstrate the potential costs and resource savings to be achieved if industry and government can work together to solve the pressing environmental issues in a balanced and cost-effective manner.

- A $35 billion (1990$) increase in environmental compliance costs for the natural gas industry (approximately a 50 percent increase over today's costs for new wells in the lower-48 states).
- A 17 TCF reduction in cumulative natural gas production with annual reductions reaching 2 TCF (10 percent) in the year 2010.
- In addition, a significant portion of the resource base is already inaccessible due to leasing moratoria on the Outer Continental Shelf (OCS), restrictions in wilderness areas, marine sanctuaries, National Parks, Fish and Wildlife Service lands, and *de facto* administrative moratoria. The full potential of these areas will not be known until access is granted.

The recommendations to mitigate these potential impacts center around the central theme of bringing more balance to the environmental legislative and regulatory arenas by modifying government processes; revising industry research, advocacy, and outreach programs; and improving public education on the net environmental benefits of natural gas. An outline of the recommendations are discussed

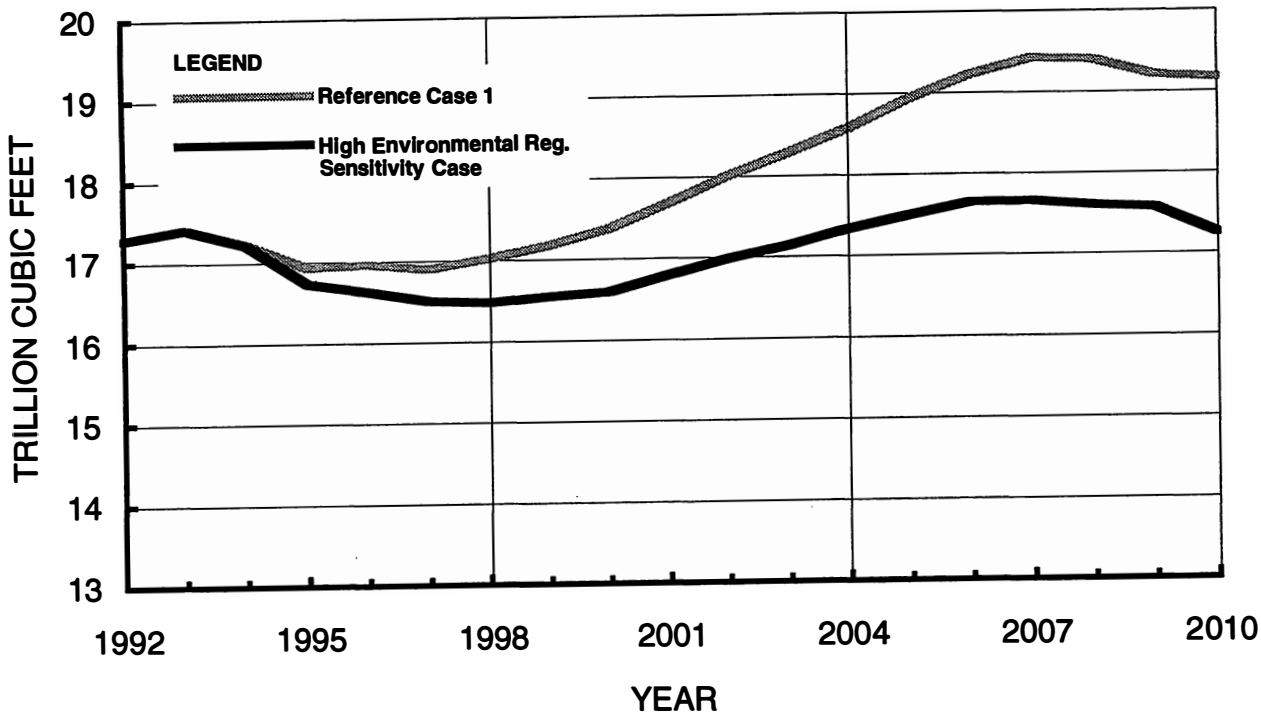


Figure 7-2. U.S. Lower-48 Gas Production.

at the end of this chapter. A more detailed discussion can be found in Volume II, Source and Supply.

Access Issues

Much of the land within the United States is public property subject to federal control. This is especially true in the western states and Alaska. These lands are administered as specialized areas such as parks and monuments, wildlife refuges, wilderness areas, national forests, and unspecialized public lands. Wilderness areas, parks and monuments, and some wildlife refuges are not available for oil and gas E&P. National forests and other public lands, however, may be available for oil and gas E&P, but are often restricted. Mineral rights and E&P authorizations on these lands are administered by federal land management agencies and are subject to laws and public decision making processes that may not apply on private lands.

The Outer Continental Shelf is another specialized area under federal jurisdiction and subject to federal environmental laws. Parts of the OCS and adjacent state waters are set aside as marine or estuarine sanctuaries and may be off limits to oil and gas E&P.

Public Lands Access

The U.S. federal land inventory consists of some 720 million acres of property onshore; nearly one-third of the entire land area of the country. Approximately 41 percent of all federal lands onshore are currently unavailable to the natural gas industry. These lands include: (1) designated wilderness, and lands recommended and under study for wilderness; (2) National Park System lands; (3) Fish and Wildlife Service lands; and (4) other lands closed by administrative action. In addition, another 20 percent of onshore federal lands, legally open to the industry, are effectively closed as a result of *de facto* moratoria and lease restrictions that significantly curtail natural gas operations. The lack of access to certain federal lands makes it doubtful that the true productive potential of these lands will be determined in the foreseeable future. The continuing trend to remove additional lands and increasingly stringent lease restrictions may have a significant, adverse impact on the role federal lands can play in any domestic natural gas strategy.

Wilderness Lands

The National Wilderness Preservation System contains over 90 million acres of designated wilderness at over 474 locations. An additional 134 million acres are currently recommended or are under study for wilderness protection, and are closed to exploration and production by congressional moratoria. Most wilderness areas are administered by four federal agencies, Bureau of Land Management, the U.S. Forest Service, the National Park Service, and the Fish and Wildlife Service.

National Park System Lands

There are approximately 80 million acres of land in the National Park System. These lands are closed to mineral leasing by the Mineral Leasing Act of 1920. Approximately 37 million of the 80 million acres have also been declared as wilderness.

Fish and Wildlife Service Lands

The Fish and Wildlife Service (FWS) administers some 89 million acres of federal land. These lands include the Wildlife Refuge System, various coordination areas, and other miscellaneous lands. Approximately 19 million acres of FWS lands are designated as wilderness. In addition, approximately 61 million acres are currently recommended or are under study for wilderness designation. Much of the remaining FWS lands is subject to regulations that prohibit or significantly restrict exploration and production activity.

Other Federal Lands

Approximately 60 million acres of additional federal land have been closed to mineral leasing by various administrative actions. These include 45 million acres affected by the Alaska Native Claims Settlement Act, and 15 million acres affected by the Endangered Species Act, the Clean Air Act, and proposals to establish "buffer zones" around national parks. Again, these lands have been withdrawn without adequate consideration of their natural gas potential.

De Facto Moratoria

Approximately 20 percent of the federal land inventory, mostly Forest Service lands, are currently inaccessible to the natural gas industry as a result of *de facto* moratoria. These restrictions flow from a variety of routine administrative actions, including unwarranted delays in issuing permits, the assignment to single-use operations lands, and the imposition of stipulations severely limiting or prohibiting leaseholders from the surface occupancy of leased lands. *De facto* moratoria have been caused by recent court decisions on National Environmental Policy Act (NEPA) compliance requirements for oil and gas leasing, resulting in a Forest Service determination that few of its forest plans contain sufficient discussion of cumulative environmental effects. The delays caused by the development of this information has brought oil and gas leasing in these areas to a halt. Since 1985, the number of acres under lease on Forest Service lands has declined by 65 percent.

OCS Leasing Restrictions

The Outer Continental Shelf is subject to the jurisdiction and control of the United States by authority of the OCS Lands Act and the Submerged Lands Act. The OCS is made available for oil and gas E&P through a bonus bid leasing system. Leasing activity is planned and announced in a 5-year OCS leasing program schedule specifying the proposed size, timing, and location of each lease sale. Long before a lease sale is held, the oil and gas industry conducts geological and geophysical (G&G) surveys of the unleased OCS lands to determine which, if any, blocks of the OCS are to be bid upon. This "presale" process is expensive and time consuming for oil and gas companies, but it is an essential step in deciding where to invest exploration capital.

Since 1982, the Congress has used the appropriations process to adjust the 5-year program schedule through "moratoria" blocking the DOI from conducting lease sales in certain OCS planning areas. The first moratorium was placed on a Central and Northern California lease sale because of environmental concerns. In subsequent years, additional areas were affected by moratoria as the OCS program became more politicized. Congress has included moratoria in every DOI appropriation since 1982, adding moratoria for the Mid- and North Atlantic, Southern California, Eastern Gulf of Mexico, North Aleutian Basin (Alaska), and Washington/Oregon OCS planning areas.

For companies that planned to invest in an OCS lease sale but were blocked by moratoria, the prelease costs for G&G data and planning overhead are sunk costs. There is also a lost opportunity cost of not being able to lease, explore, and develop new oil and gas.

In 1984, the Congress added a new moratorium on exploration drilling on existing leases in the Eastern Gulf of Mexico. Since then, such drilling moratoria have also been enacted in other planning areas. Companies holding and paying for existing leases under drilling moratoria cannot drill for a return on their investment or abandon the investment. In 1990, the President placed some of the more controversial OCS planning areas under an administrative moratorium. These areas are to be studied and reconsidered for leasing after the year 2000.

Besides the sunk costs and lost opportunity costs, the loss of access to OCS lands creates uncertainty about investing in the OCS. The reduction in available acreage for exploration reduces the pace of offshore drilling which sends economic ripples through the OCS service industries. In turn, the slowdown in those industries affects their suppliers. Eventually, the effect of a moratorium is the loss of the equipment, expertise, and infrastructure to support E&P activities in an area. The loss of drilling capability has serious, long-term implications for domestic energy production, imports of oil and the balance of trade, and the energy options available to the nation. Moratoria even affect the revenues of the U.S. Treasury through lost bonus bids, rents, and royalties.

Other Initiatives That Affect E&P Costs and Access

There are other laws or issues that add to the cost of domestic gas E&P by causing delays, requiring site-specific mitigation measures, or changing new exploration opportunities. Also, certain laws may block or limit access to public and private lands and the OCS. In some cases the laws do not absolutely prohibit activities, but they may make them so controlled or costly as to be impractical or uneconomical.

The following environmental initiatives fall into this category:

- Coastal Zone Management Act of 1972
- Marine Sanctuary Program (Marine Protection, Research, and Sanctuaries Act of 1972)
- Marine Mammal Protection Act of 1972
- Endangered Species Act of 1972
- Wetlands Protection (Clean Water Act 1977)
- Comprehensive Environmental Response, Compensation, and Liability Act of 1980 and Superfund Amendments and Reauthorization Act of 1986
- Oil Pollution Act of 1990
- Toxic Substances Control Act of 1976
- Naturally Occurring Radioactive Material

Environmental Constraints and Impacts on Transmission and Storage

The major environmental constraints facing the transmission sector of the industry include new Clean Air Act requirements and pipeline right-of-way access/permitting issues, with right-of-way access and permitting providing the most serious obstacles to increasing the availability of natural gas.

Clean Air Act Requirements

The major Clean Air Act impacts on natural gas transmission and storage facilities will be requirements for NOx controls along with hydrocarbon controls. New pipeline compressor stations will be required to have the most efficient, clean-burning prime mover (i.e., internal combustion engine and gas turbine) technology available, and existing stations may be required to undergo extensive retrofitting or replacement. In non-attainment areas along with advanced controls, enhanced emission offset requirements will be required for the permitting of new or modified facilities.

The Clean Air Act Amendments of 1990 modified the focus of ozone non-attainment strategies to include NOx as well as hydrocarbon controls. The result will be a series of NOx control requirements developed at the state and local level via the development of State Implementation Plans (SIPs). The actual level of control required will vary as a function of the severity of the local air quality problem and the local SIP strategy. Emission control require-

ments for existing facilities could range from moderate combustion modification approaches (modified heads on internal combustion engines and water injection on gas turbines, etc.) to advanced catalytic controls (i.e., Selective Catalytic Reduction). New or modified facilities that exceed 25 tons/year in non-attainment areas, will have to install "Lowest Achievable Emission Rate" technology (i.e., Selective Catalytic Reduction), and purchase or find emission offsets at levels greater than 1 to 1 (depending upon the severity of the air quality problem) for the NOx emissions they generate.

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.

Pipeline Right-Of-Way Access and Permitting Issues

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 significantly extend the regulatory approval process for new construction. Additionally, filing of permit 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 environmentally attractive than natural gas, but that 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 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 a new pipeline. This 36-mile project required 20 environmental permits (exclusive of construction permits) from more than 9 different regulatory agencies. Wetland 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, i.e., "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.

Constraints and Impacts on the End Use of Natural Gas

Volume III, Demand and Distribution, and its ten supporting regional reports, identify not only the environmental impacts, but also the environmental advantages of natural gas for the end-use customer. The results of this analysis indicate that while natural gas can significantly contribute to the reduction of a number of important pollutants, constraints do exist that inhibit the industry from fully serving the environmental market. The following discusses constraints for each of the key consumer sectors.

Residential and Commercial Constraints

The increased emphasis on environmental costs as a result of the Clean Air Act Amendments of 1990 may provide an advantage to natural gas relative to electricity and other fuels. The advantages result from three basic factors: (1) an increase in the relative prices of alternatives to natural gas; (2) a direct prohibition on some pollutants like chlorofluorocarbons (CFCs); and (3) incorporation of environmental externality costs into the utility planning process.

The biggest constraint in the residential and commercial area may be the lack of a united and aggressive industry effort to capitalize on the environmental benefits of natural gas

with the American consumer. Opportunities exist in both customer education and in the development of new product applications and new technologies utilizing natural gas.

Industrial Constraints

Natural gas is used in the industrial sector both as a feedstock and as fuel for direct heat, steam, and power generation. The CAA Amendments present an opportunity for the gas industry to provide gas based solutions to help industrial customers meet compliance requirements. In addition to helping minimize air emissions, opportunities for reducing waste generation and minimizing future potential site remediation are also areas where gas offers significant help to industrial customers in meeting environmental requirements while at the same time remaining competitive.

There is, however, a potential downside to Clean Air Act regulations, particularly for new or modified sources in non-attainment areas. In particular, Title I of the CAA Amendments requires that all new or modified sources emitting greater than 25 tons per year of NOx[1] in ozone non-attainment areas, must undergo new source review, install "lowest achievable emission rate" controls,[2] and purchase or find NOx offsets for the NOx they do emit. The downside for gas equipment is that what few emission they emit are produced on site at the facility, whereas the emissions that occur associated with a similar electrical applications occur at a generating plant that may be miles outside of an urban area and thus may have little direct effect on the air quality of the area they serve. The end result is that gas equipment may be better from a global environmental perspective, but electric equipment may be easier and cheaper to permit because they have little or no local emission offset requirements.

Electric Generation Constraints

Natural gas has important environmental advantages over competing fuels in the electric generation market because of lower emissions of SOx, NOx, CO, CO2, and particulates. The major constraints on the use of natural gas in the electric generating sector are the direct result of the merging of environmental regulation with public policy issues. The two big issues are state "environmental externalities" requirements and government subsidies for other fuels.

State Environmental Externalities

Several state regulatory commissions and siting boards have begun requiring that electric utilities take "environmental externalities" into account when developing their integrated resource plans. Requirements vary from state to state, but "externality" requirements generally result in an advantage for natural gas compared to other fossil fuels, but create a disadvantage when natural gas is compared to conservation and some renewable energy sources.

Government Subsidies for Other Fuels

The federal government and some state governments have adopted measures that subsidize energy sources that compete with natural gas and thus tend to hold down demand. In the environmental area these include:

- Tax reductions for electric utilities using indigenous coal supplies (e.g., a $3 per ton tax credit in Virginia)
- Statutes, regulatory requirements, and political pressure encouraging electric utilities to install scrubbers so that they can continue to use indigenous coal rather than switching to natural gas or to a low-sulfur coal imported form another state
- Federal payments for cleaning up uranium wastes (mill tailings) and other nuclear energy wastes associated with commercial nuclear power projects.

In addition to these major constraints, some utilities may find it economically more attractive to select alternatives to gas where capital costs for controls may be projected over the lifetime of the technology. Some capital investments may also permit the utilities to gain more credits under the allowance system established in the Clean Air Act Amendments.

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[1] Boiler installations using greater than 400,000 MCF per year and high temperature gas processes or facilities using as little as 40,000 MCF per year could be affected.

[2] "Lowest achievable emission rate" controls are those technologies which are technically feasible with no consideration given to cost.

NATURAL GAS AS A PREFERRED FUEL

Environmental Benefits of Natural Gas as a Fuel

Natural gas or methane is a clear, odorless gas (odorents are added for retail use). Being the lightest hydrocarbon fuel, it burns easily with little or no smoke (soot or particulate) and it produces the least amount of combustion CO_2 relative to other fossil fuels.

Natural gas is generally recognized as having a number of important environmental advantages over other fossil fuels. These advantages include:

- ***Lower Combustion Emissions in Large Stationary Applications:***
  - Virtually no sulfur.
  - No NOx emissions from fuel based nitrogen.
  - Extremely low particulate emissions.
  - No non-methane volatile hydrocarbon emissions.
  - 25 percent lower CO_2 emissions than oil and 49 percent lower than coal (**Note:** this advantage is offset somewhat by the fact that methane itself is considered to be a greenhouse gas with a potency factor greater than CO_2).

  The value of natural gas in reducing SO_2 and NOx emissions can be seen by looking at Table 7-1, showing the national inventory for these emissions relative to other fuels.

- ***Lower CO_2 in Residential Applications.*** The American Gas Association study, Potential Carbon Dioxide Emissions Reductions from Residential Space Heating Conversions (April 1991), found that the conversion of less efficient conventional heating systems (low AFUE natural gas, fuel oil, and electricity) to new, more efficient natural gas systems can reduce CO2 emissions by as much as 75 percent. The study also concluded the following:
  - The annual CO_2 emissions attributable to a new, efficient natural gas space heating system in a home are approximately 75 percent lower than that of an existing electric resistance heating system in the same size home, with electricity supplied by power plants.
  - Converting existing fuel oil systems to new natural gas space heating can reduce CO_2 by about 47 percent.
  - Converting an existing heat pump to new natural gas space heating can reduce CO_2 by approximately 62 percent.
  - New natural gas space heating systems are about 50 percent better for the environment than the new electric heat pump system.

TABLE 7-1

U.S. SOX/NOX EMISSION INVENTORY BY FUEL TYPE — 1980 (Percentages)

	U. S. Fossil Energy Consumption	SOx	NOx	SOx & NOx
Natural Gas	30	Nil	15	7
Coal	23	80	33	58
Oil	23	18	28	23
Total	**100**	**100**	**100**	**100**

SOURCE: Gas Research Institute.

- *Other Environmental Advantages:*
  - No solid waste is generated at the user's site (compared to oil and coal ash and sludge).
  - Pipelines have less visual impact than electric transmission lines, railroads, coal piles, and oil storage tanks, and they are not as noisy.
  - Much less severe environmental impacts from leaks and spills.
  - Fewer operating problems and therefore fewer emissions from operational upsets.

PUBLIC POLICY AND PERCEPTION ISSUES

Environmental Politics

The public, including many of its government institutions, has a general mistrust of business and particularly the energy business. Natural gas production is associated with oil production, and carries with it the burden of prior oil politics as well as highly publicized environmental incidents such as crude oil spills. Underlying this lack of trust is a basic feeling that the oil industry does not have the same values and respect for the environment as the public. Industry information on environmental matters is generally suspect, diminishing overall effectiveness. Some governmental agencies, particularly in the producing states, are seen as too close to the industry and are also suspect as sources of credible information.

Legislative and regulatory processes, because they are often confrontational and procedurally committed to airing every concern and giving every opportunity to be involved in the process, are very slow and costly. This system is heavily tilted toward environmental activism by allowing indefinite delays of energy projects.

Little recognition is given to the environmental benefits of natural gas or its benefits to the economy in producing jobs, tax revenues, and energy security. Traditional economic regulation has often put natural gas at a disadvantage by not recognizing its environmental benefits. Some states have intentionally skewed regulation that might otherwise favor natural gas but could diminish the use of locally abundant industries like coal; for instance, subsidies and/or requirements for electric utilities in coal-producing states for installation of scrubbers to meet clean air requirements and tax incentives for utilities that burn indigenous coal provide an advantage to coal over natural gas.

An area of increasing influence at the state level involves an age-old concept—NIMBY (Not In My Back Yard)—that has been successfully extended to environmental regulation. For example, the addition of gathering and storage facilities to an area may be opposed by the public because they are unsightly. State regulators may then restrict the addition of such facilities in order to appease opponents. In order to keep the existing facilities from garnering monopolistic rents due to restricted completion because of NIMBY complaints, such facilities may now become regulated. The San Juan Basin is one example of an area where, despite its abundance of natural gas and a great need for production wells and gathering facilities, the unintended consequences of restricted well and gathering facilities under the guise of environmental regulation may be to squelch production of natural gas.

The impacts of the regulatory process are not fully appreciated by regulators, legislators, or the general public. Inadequate consideration is given to the impact on industry of overlapping regulations, lack of clear definition of jurisdiction by the various regulatory bodies, and inconsistent energy policy among the various elements of government.

Compliance with environmental regulations continues to be an ever increasing component of the cost of natural gas. Environmental regulations are affecting more and more aspects of gas operations, and some of the increasingly complex requirements may even exceed technologic practicability or possibility. In certain instances, compliance with regulations that protect one medium, like water, may affect the industry's ability to comply with regulation to protect other media, like land and air. Such cross-media effects are only beginning to be recognized by government regulators. Environmental requirements under some laws may have reached, and gone beyond, the point of diminishing returns, where the costs of achieving small increments of environmental improvement outweigh the benefits realized.

These factors highlight the need for a coherent government approach to environmental regulation to access the cumulative effect of all environmental regulation on the industry. In addition, the need exists for a consistent uniform mechanism to adequately balance the upstream costs and benefits of these regulations along with an analysis of the downstream benefits of natural gas.

Environmental Externalities

A number of states are attempting to require electric utilities to take "environmental externalities" into account when they make their resource decisions. State regulatory commission requirements that electric utilities prepare Integrated Resource Plans (IRPs) are the vehicle for requiring consideration of "environmental externalities." This movement offers a potential opportunity, and some risks, for expanding natural gas markets. Efforts to include "environmental externalities" in IRP decisions are well underway in several states with Massachusetts, New York, California, Illinois, Colorado, and Nevada among the leaders. Some local gas companies have already participated actively in proceedings (e.g., Boston Gas in Massachusetts IRP dockets 89-239 and 91-131).

The Conceptual Basis For "Environmental Externalities." Economists have long contended that all the real costs and benefits to society of actions taken by individuals or organizations often are not reflected in the price paid by consumers of the products and services that are consumed. The "environmental externalities" movement in IRP requirements uses the economists' concept but focuses on the environmental impacts associated with the production of electricity.

The Controversies Surrounding "Environmental Externalities." The application of "environmental externalities" has raised a number of key public policy issues, the most contentious of which is centered around the assignment of monetary values to "environmental externalities" and the requirement that these "adders" be included when considering alternative supply-side (e.g., new or repowered generating capacity) and demand-side (e.g., conservation and load management) actions necessary to bring projected electricity demand and generating capacity into reasonable balance at lowest cost to electric customers (which is the underlying rationale for IRPs). The critical decision facing regulators is whether these values should be based on damage (i.e., to human health, environment, etc.) or cost of control (i.e., to reduce emissions suspected of causing damage).

Other important issues in the "environmental externalities" debate include how far back up the chain toward the source you go (i.e., the coal mine, the wellhead, etc.) and what is included in the analysis (i.e., do you include the emissions from the steel used to make the trucks to haul the coal, or do you just include the transportation emissions?).

"Environmental externalities" have the potential to create increased opportunities for natural gas because of its "clean-burning" characteristics. But within the concept are some issues that need to be recognized and managed carefully if the natural gas industry if to take advantage of the opportunity. These issues include:

- Concern and often open opposition to "environmental externalities" by the electric utilities, a large potential customer for natural gas
- Energy conservation and some renewables tend to have an advantage over natural gas when externalities "adders" are taken into account
- Methane is recognized as a "greenhouse gas" with more potency than CO_2.

A subset of the issue of "environmental externalities" is the issue of energy conservation and the use of other fuels to replace nonrenewable hydrocarbons. There will likely be continuing efforts to decrease U.S. dependence on, and demand for, oil and even gas as fuels.

The final section of this chapter outlines recommendations for government and industry on the subject of "environmental externalities."

Decentralized, Market-Oriented Approaches

A decentralized, market-oriented approach is beginning to develop as an alternative to the 1970s and 1980s command and control approach to environmental legislation and regulation. The marketable emission rights component of the 1990 Clean Air Act

Amendment's acid rain control program is an example of this technique. Reduction targets for emissions of various pollutants are set and industry is left to find the best ways of curtailing emission. The targets are met by facility modification or by purchasing credits from other facilities that exceed their target reductions and thereby generate surplus emission credits. The concept, long promoted by industry, is gaining favor with regulatory agencies as the incremental cost of new control measures continues to escalate since market-based systems create the driving force and allow industry to create optimum emission control solutions (i.e., minimum cost per unit of pollution abatement).

EMERGING ENVIRONMENTAL ISSUES

Global Climate Change

Global climate change caused by the gradual buildup of carbon dioxide, methane, and other greenhouse gases is an issue of growing public policy and scientific debate. As the debate continues, it may serve as a driving force for legislation and regulation to minimize the consumption of fossil fuels with preference given to those fossil fuels that minimize the emission of these gases.

Natural gas is the lowest emitter of combustion carbon dioxide, but it is itself a greenhouse gas which may draw attention to minimizing emissions from production transportation and storage. There are few reliable, objective data on the question of methane emissions. The Gas Research Institute has initiated an aggressive program with the 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.[3] Natural gas operations account for only a small fraction of world methane emissions and ranks after the following other sources: natural wetlands, animals, biomass burning, rice paddies, landfills, termites, methane hydrates, waste water, oceans and fresh water, and coal.[4]

Bio-diversity

A very clear trend in environmental law and regulation will be the focus on ecological protection and bio-diversity rather than just protecting individual resources. This more holistic approach is being promoted to protect ecological systems and to preserve, for scientific research and study, all of the lifeforms in those systems. Bio-diversity will have its biggest impact on permitting and assess issues.

RECOMMENDATIONS TO ADDRESS THE ISSUES

Recommendations for Government

Recommendation 1 — Legislative and Regulatory Policy and Practices

Create a balance between costs and benefits in the legislative and regulatory process for environmental and access issues that affect the natural gas industry (i.e., exploration and production, transmission, and consumers). This includes the direct recognition of the environmental benefits of natural gas as a fuel.

The rapid urbanization and the continued industrialization of the country, coupled with perceived historical poor performance of both government and industry, has created a climate for overregulation and limits on access that often exceeds what would otherwise be dictated in a balanced, scientific evaluation of the issue. In most cases, the downstream benefit (i.e., the net environmental benefit) of natural gas is often not included in the public policy debate on upstream environmental issues.

The solution is for government, at all levels, to create a balance between costs and benefits in the legislative and regulatory process for en-

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

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

vironmental and access issues affecting the natural gas industry. This includes the direct recognition of the environmental benefits of natural gas as a clean burning fuel. A balanced approach will ensure adequate protection of the environment while minimizing the financial impact on industry and provide access to the available resources. Specific recommendations for government are outlined below and discussed in more detail in Volumes II through V.

Implementing Items

Legislative and Regulatory Balance

1. Extend (or reintroduce) the federal regulatory moratorium to review and modify the current regulatory and permitting process by:
   - Monitoring the effects of regulatory stability
   - Developing accepted methodologies for developing cost-benefit information
   - Researching the cost and benefits of current regulations
   - Developing methodologies to bring balance to permitting and access issues (see Volume II, Source and Supply).
2. Modify the legislative and regulatory process to ensure that cost-benefit analyses are completed and the net environmental benefits of natural gas are included in the decision making process (see Volume II, Source and Supply).
3. Insert cost-benefit analysis into federal and state regulatory decision making in FERC and state public utility commissions (see Volume II, Source and Supply).

Permitting and Access

4. Develop an approach to leasing and permitting to ensure access to prospective acreage for prudent, environmentally sound exploration and development programs. This includes a reevaluation of acreage currently under moratoria as their terms expire.
5. Modify federal leasing programs so that successful bids that are based on accepted environmental guidelines would come with drilling permits or otherwise reduce lessees' exposure to the risk that changes in environmental laws and regulations can hinder exploration and production on their leases (see Volume II, Source and Supply).
6. Modify the OCS Lands Act to share some of the current federal revenue with local jurisdictions (see Volume II, Source and Supply).
7. Expedite the review and approval process for new pipeline projects at the federal, state, and local levels without diluting substantive environmental protection (see Volume IV, Transmission and Storage).

End-Use Restrictions

8. Develop a technically based and balanced approach to designing and implementing the new regulatory requirements under the 1990 Clean Air Act Amendments.
9. Government, at all levels, should move forward cautiously with the use of environmental externalities until they have carefully researched methodologies and have developed a well thought out approach for implementation.

Recommendations for Industry

Recommendation 1 — Environmental Technology

Develop and supply timely and credible technical data for use in communication efforts with government, other industry groups, environmental groups, and the general public. Focus research activities toward developing more cost-effective technical solutions to the environmental challenges facing the natural gas industry.

- ***Technical Data.*** Industry has historically believed that it is government's role to determine the need for environmental legislation or regulation and develop technical data for comprehensive cost-benefit analyses. As a result, industry's participation has been often more as a reactive critic rather than as a contributor or as a collaborator.

As government budgets tighten and the complexity of environmental issues increases, it is becoming more and more difficult for legislative or regulatory staffs to develop adequate cost-benefit analyses and other technical and scientific data required. The government simply does not have the human and financial resources nor an adequate knowledge of industry to do the job with the level of accuracy necessary. This is not a criticism but a fact. It is no longer an issue of *who* has the legal responsibility to ensure that creditable analyses are done. The issue is *how* the necessary work can be done to ensure that informed decisions are made so that natural gas can play an important role in the nation's energy future.

- ***Research and Development.*** In determining the level of control or the type of environmental controls necessary, industry has historically deferred to government to identify "Best Available Control Technology" or "Lowest Achievable Emission Rate." In fact, industry has often taken safe harbor in arguing that proposed controls are not currently demonstrated technology. The result has been in effect the delegation of the technology, and therefore the level of control, to either inexperienced regulators, their consultants, environmental groups, or some third-party entrepreneur, none of whom understand industry's constraints or have a vested interest in the profitability of the industry. This approach has created a confrontational regulatory development process that results in at best a negotiated compromise that is often politically driven, inefficient, and more often than not, excessive.

The solution to the above problems is to increase industry's involvement in developing cost-benefit and other technical and scientific information on the environmental issues that impact the natural gas industry and refocus industry and government environmental R&D efforts on Pollution Prevention and the development of more innovative and cost-effective environmental solutions. Throughout this discussion it is important to note that there are also important opportunities for government to partner with industry in many of these recommendations.

Specific recommendations are outlined below and discussed in more detail in Volumes II through V.

Implementing Items

Technical Information

1. Initiate an industry/government sponsored project to develop a methodology for doing cost-benefit evaluations and document the results in a "How To" manual for industry, government, and public use. Participants in the project should be drawn from industry, government, and the environmental community (see Volume II, Source and Supply).

2. Based upon the output from Item 1 above, enhance the natural gas industry's capability to develop credible and timely cost-benefit and other technical data on both upstream (exploration and production), transmission (pipeline), and downstream (consumer/user) environmental issues. These analyses would address not only the absolute cost benefit of the specific issue (i.e., the direct costs verses environmental benefits), but would also include the net environmental benefit of the use of natural gas relative to other fuels (see Volume II, Source and Supply).

3. Gather the technical information and knowledge necessary for the natural gas industry to develop a strategy for dealing with environmental externalities. This includes reviewing and monitoring work already in progress as well as any original work that might be necessary.

   Examples of key issues include:

   - Methodologies for assigning values to environmental adders.
   - The role of methane in the ongoing global climate change debate.

Research and Development

4. Refocus industry environmental R&D efforts toward Pollution Prevention to develop more innovative and cost-effective solutions to environmental problems (see Volume II, Source and Supply).

Examples include developing techniques to:

- Minimize methane emissions from E&P operations, transmission and storage, and end use.
- Develop emission control and retrofit technology for compressor prime movers (i.e., I. C. Engines and Gas Turbines), and more efficient, cleaner burning new prime movers, to meet increasingly stringent emission requirements (see Volume IV, Transmission and Storage).
- Reduce NOx emissions from natural gas vehicles to levels that are competitive with other low emission transportation fuels.

Recommendation 2 — Education and Communication

Enhance education programs to increase the public's understanding of the positive role natural gas can play in solving the nation's environmental problems. Target audiences include federal, state, and local governments, other industry groups, environmental organizations, and the general public.

The public view of the role of natural gas in the national energy mix is currently clouded by a number of misconceptions about the safety and environmental benefits of natural gas and a generally poor industry public image.

The pubic misconceptions about natural gas vary regionally depending upon how widely gas is currently being used and how aggressive negative advertisements are for competing fuels. In areas like the west, where gas is a "natural" part of everyday life, safety is not an issue and the existing paradigm gladly accepts the role of gas as an intrinsically clean, efficient, convenient, and safe energy source. In the east, where gas is less prevalent and the existing paradigm includes a much higher reliance on electricity, oil, and coal, the public's comfort level with the use of natural gas is much lower. The problem is often exacerbated by negative advertising by competing industries.

The environmental benefits of natural gas are not very well understood by the general public. In the west, natural gas is marketed widely as a "clean" fuel, but the public's perception is more from a housekeeping point of view than from an environmental point of view. The general public has not made the environmental connection yet. In the east, where natural gas is less familiar, the problem is even more severe. In the last five to ten years, government and the natural gas industry have failed to aggressively develop the potential natural partnerships and/or coalitions with consumer and environmental interest groups to take maximum advantage of the environmental benefits of natural gas.

The oil and natural gas industry contributes to its image problem by its general behavior. It is a predominately inwardly focused industry that traditionally makes decisions from the perspective of scientists and engineers rather than looking more outwardly and factoring in the goals, needs, and expectations of an ever changing public. This behavior is often viewed by the public as arrogant. This perceived arrogance coupled with periodic events such as spills and releases has resulted in the industry's poor public image.

The solutions to overcoming the public's misperceptions will hinge upon future industry performance and the ability of the industry to carry its message to the public through enhanced and innovative education and outreach programs. Throughout this discussion, it is important to note that there are also important opportunities for government to partner with industry in many of these recommendations.

Specific recommendations for enhanced education and outreach programs are outlined below and discussed in more detail in Volumes II through V.

Implementing Items

1. Initiate an industry/government project to develop methodologies and tools for developing education and communication efforts to market the role of natural gas in a balanced but comprehensive energy conservation, pollution prevention, and energy development program. The project team should include representation from all potential target audiences and/or rely heavily

on "client feedback." The methodology would be documented in a "How To" and/or training manual for industry and government use (see Volume II, Source and Supply).

2. Based upon the work product from Item 1 above, develop an education and communication effort to market the role of natural gas in a balanced but comprehensive energy conservation, pollution prevention, and energy development program (see Volumes II through V).
3. Form a joint, industry, government, and environmental group coalition(s) to develop new ideas and concepts to facilitate compromise and progress rather than continued confrontation. Increase participation in existing public advisory committees created to provide input into the legislative, regulatory, and permitting process (see Volume II, Source and Supply).
4. 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 (see Volume IV, Transmission and Storage).

Recommendation 3 — New Technology and Innovative Industry Strategies

Develop new technology and innovative industry strategies to better align the natural gas industry's goals with the public's needs and expectations in order to expand markets and create more timely and efficient solutions to environmental, permitting, and access issues. Create win/win situations for the natural gas industry; its customers, federal, state, and local governments; environmental groups; and the general public.

Like most businesses, the natural gas industry has traditionally planned and facilitated its activity through traditional business, engineering, and scientific processes without significant evaluation (other than natural gas consumption) of the goals, needs, and expectations of the general public. Consequently, the "public," which can significantly impact gas development through the government permit process, often stands in the way of new projects and demands to be included in the decision making process. The basic objective under this recommendation is to develop and maintain a better understanding of the public's expectations for the gas industry relative to environmental issues and to utilize this knowledge for the following purposes:

- Develop more effective industry advocacy strategies and positions on environmental legislative and regulatory initiatives
- Design new development projects that meet not only industry's needs, but also the needs and expectations of the public.

In many respects this recommendation draws on one of the key elements of the "quality" movement that is currently sweeping the country's business community. That is, know your customers and design your business strategies to meet their needs and expectations. It represents a new approach to managing environmental issues, and it is an opportunity to create innovative solutions to emerging problems while at the same time developing business opportunities for the industry.

The following items are examples of the kind of innovative or "breakthrough" thinking we are trying to convey. In some cases, the examples are concepts that are currently being tried successfully in other industries; in other cases, they are merely the product of a brainstorming process. The recommendations are not intended to automatically apply, may not always be necessary or effective for all situations or for all parts of the country, and more importantly, should not be mandated by federal, state, or local governments. The goal is to improve the efficiency of the process where it is not working well, not to increase costs where things are working well. Part of the implementation process for this recommendation would include a critical analysis of the local, regional, and/or national situation before developing a specific strategic action plan.

The specific recommendations are itemized below and discussed in more detail in the subsequent volumes of this report.

Implementing Items

1. Develop new and innovative approaches to integrate constructive public input into the project development and permitting process.

   Examples include using community "thought leaders" as project consultants and/or adapting the negotiated rule-making process for use in permitting and access issues (see Volume II, Source and Supply, for more detail).

2. Develop and/or participate in innovative cooperative community programs to create partnerships with local government and community interest groups.

   One example would be to support comprehensive integrated community energy development, conservation, and management programs that would encourage energy conservation/efficiency measures, transportation control measures (ridesharing, etc.), improved public transportation, natural gas vehicle fleets (public and private), and energy development opportunities. This approach would align natural gas development with local or regional energy management needs, while creating opportunities to promote the use of clean burning natural gas (see Volume II, Source and Supply).

3. Improve the integration of environmental issues into strategic business planning and decision-making processes (see Volume II, Source and Supply).

   One example would be to improve the methods used to account for environmental constraints in the industry's financial decision-making process.

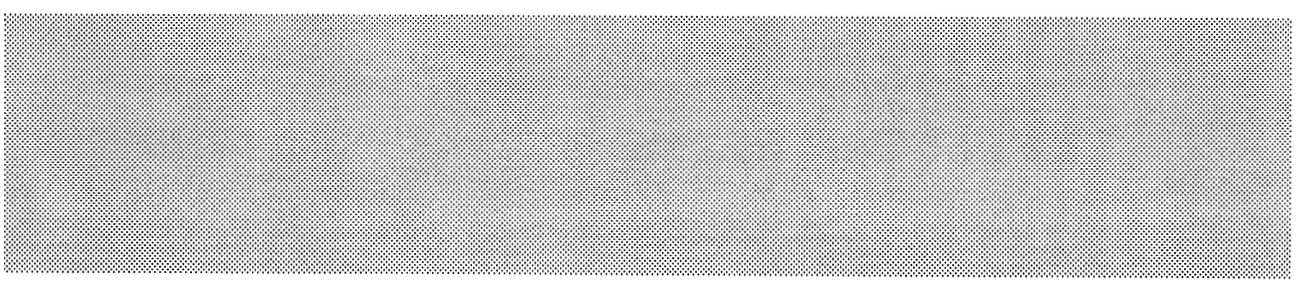
4. After gathering the appropriate technical data (outlined under Industry Recommendation Number 1 above), determine whether it is necessary to develop a natural gas industry strategy on environmental externalities.

5. Develop a united natural gas industry strategy for promoting the use of natural gas vehicles (NGVs).

   Examples include promoting the use of NGVs in fleet applications both inside and outside the industry, and supporting vehicle manufacturers in their efforts to standardize and mass produce NGVs.

6. Develop direct business opportunities for the natural gas industry by developing new or adapting existing products, processes, and services to meet the needs of the American consumer (see Volume III, Demand and Distribution).

   Examples include combined natural gas heating and cooling for residential and commercial use, home refueling capabilities for NGVs, assisting customers obtain environmental permits, etc.



CHAPTER EIGHT
TECHNOLOGY

OVERVIEW

The natural gas industry consists of four main segments—producers, transmission companies, distribution companies, and consumers. Advances in technology have been a part of the industry since its inception. In fact, the use of gas in street lighting was a major technological advance, and is generally credited with the beginning of the industry. Continuing technological advances have allowed the industry to become a significant contributor to the national energy supply.

In the production sector, technological advancement has brought new resources into the accessible resource base through deeper drilling capabilities, deeper water drilling and production capabilities, improved recovery from known reservoirs, new knowledge associated with tighter (lower quality) reservoirs, and knowledge of how to produce coalbed methane to name only a few examples. These advances have served to offset the normal depletion of high quality resources from the resource base and made it possible to provide adequate supply with competitive prices.

Technology advancement in the transmission and storage areas have allowed gas to efficiently serve new markets, attach new fields and reservoirs, and manage large seasonal fluctuations in demand.

Technological improvements in the energy efficiency of gas-fired appliances and process equipment are among the reasons total gas use declined even with the addition of new customers.

The outlook for natural gas depicted by this study is predicated on the continual development of technology in the producing segment, increased use of technology improvements in the transmission and distribution segments, and significantly improved commercialization of technology developed for the end-use segment of the natural gas market. Continued technology development in the supply segment is needed to help ensure the continued availability of supply capability at a competitive price. The technology advancement and commercialization in the end-use sector are needed to provide continual progress in equipment efficiencies to keep pace with other industries to maintain existing markets, and to develop new equipment to capture additional markets. All of this technology development and commercialization requires investment.

The primary issue facing the gas industry is:

How can the funding for the necessary development and commercialization of technology be assured in order to realize the new natural gas world of growing demand?

In 1992, the total research and development (R&D) investment in natural gas technology development was estimated to be $750 million, with companies and associations providing

$656 million or 87 percent. About $440 million of this investment is risk capital while the rest is funded either directly by the federal government or recovered from rate payers, e.g., through the FERC-approved funding of the Gas Research Institute (GRI).

While the industry has been successful in developing technology, it has achieved only limited commercial success in the end-use technologies. There are many reasons for this failure, but the primary one is the regulated nature of the industry at the interface with the consumer.

Due to this separation of the customer from the service provider, commercialization has been identified as a major limitation to the potential for increasing the natural gas contribution to the national energy mix. Consequently, the commercialization issue can be summarized as: "What incentives can be created to enhance investment in commercialization when the benefits are limited for the regulated segments of the industry?"

While investment by the producing segment will likely continue, there is concern that the level of this activity might be adversely impacted by the current economic conditions, especially natural gas prices, and the industry downsizings. Thus, the issues facing this segment are: (1) With the majors undergoing restructuring programs and focusing their investment programs on international operations, will adequate investment in natural gas supply related R&D continue? and (2) With the independent sector growing its share of domestic natural gas production, how can technology transfer programs be enhanced to ensure the continued technology advancement?

While each of the industry segments is heavily impacted by technology results, each is driven by different forces relating to technology development. However, the industry supports a ***fundamental premise*** for the funding of R&D.

Support for R&D programs should come first from private industry using risk capital and responding to market signals with the benefits accruing to the investor in recognition of the risk taken.

Recommendations

In order to address the issues of adequate funding for the research, development, and commercialization and significantly increasing success in end-use commercialization efforts necessary to support the underlying technological advancement embodied in this study, the National Petroleum Council makes the following recommendations to individual companies in the industry, industry associations like the GRI and the American Gas Association (AGA), and government agencies at both federal and state levels.

Industry

Each segment of the industry must ensure that the economic use of its own technology is a priority for its own facilities and operations in order to provide the demonstration sites necessary for commercialization efforts and to demonstrate its belief in these technologies and is communicated in its public presentations.

Individual companies must become comfortable with the investment in R&D and communicate with the market its benefits.

Industry segments must recognize the inherent limitations of a regulated structure and devise mechanisms to allow the benefits of R&D to flow to the investors.

Establish a mechanism to fund a research association, like the GRI, without generating any competitive advantages or disadvantages.

Associations

The associations like the Gas Research Institute need to find ways to ensure commercialization of their developments.

Industry trade associations should focus most of their efforts on the market segment acting as a constraint, i.e., supply or demand, and continue to intensify their communication campaigns aimed at educating the public, law makers, and regulators.

A broad-based industry association, such as the Natural Gas Council, should undertake a study of the commercialization issue with the objective of developing recommendations to overcome the limitations on commercialization efforts.

Federal Government

Recognizing the new perception of an abundant natural gas resource base and the cost and environmental benefits of natural gas, the National Petroleum Council proposes that the federal government through agencies within the Department of Energy (DOE) and the Department of Interior (DOI) expand its gas supply R&D effort providing a more balanced distribution between coal and natural gas.

Specifically, the federal government should:

- Target a sustainable research, development, and demonstration investment program level of about $250 million per year in natural gas as an appropriate level to achieve the technology advancement needed to allow natural gas to expand its contribution to the national energy mix. This level is consistent with the supporting documentation of the recent National Energy Strategy, and several recent studies including those by the Washington Policy Analysis Group[1] and the American Gas Association.[2]
- Direct the DOE, in concert with industry and regulators, to review the limitations on commercialization efforts caused by a cost-based regulation system.
- Continue to increase efforts to develop new ways to sponsor cooperative research projects with industry participants—with particular emphasis on achieving increased participation by independent producers.
- Allow companies, particularly smaller companies, to participate through in-kind contributions that are defined as acceptable under federal procurement rules and regulations.
- Support the fundamental premise that private industry should be the first source of funding for R&D investment by focusing government investments on areas recommended as appropriate by industry.
- Continue to increase its coordination efforts with industry organizations and associations.
- Ensure that regulations for government installations do not restrict natural gas usage.
- With industry participation, explore the support for longer range, more basic research while maintaining a high degree of practicality.
- Make cost-effective environmental compliance technology development a top priority.
- In cooperation with industry and established industry associations, pursue more aggressive technology transfer programs such as sponsoring more DOE-funded projects and workshops.
- Continue to support ongoing research, such as that undertaken by the GRI.

State Government

At the state level, Public Utility Commissions (PUCs) should:

- Recognize the inherent limitations of a regulated structure and devise mechanisms to allow the benefits of R&D to flow to the investors.
- Become comfortable with the need for investment in R&D, its long-term nature, and the nature of benefits from the investment—i.e., slow and gradual.

CURRENT NATURAL GAS RELATED R&D INVESTMENT

The natural gas industry requires a robust research and development program spanning all aspects from supply through end use. For 1992, estimated R&D investment was $750 million, with companies and associations providing $656 million or 87 percent. (See Table 8-1.)

The information for producers and service companies is estimated from a detail survey of R&D expenditures in the exploration and producing sector of the industry for the years 1988 and 1992 conducted by ICF Resources, Inc., for

[1] William F. Martin and Scott L. Campbell, partners, *U.S. Natural Gas: An Investment Strategy for Energy and Environment,* a research report of Washington Policy Analysis, A Miller & Chevalier Consulting Group, 1992, page 14.

[2] American Gas Association, *Ten Year Funding Recommendation by the Natural Gas Industry – Program Descriptions,* August 1991, page v.

TABLE 8-1

NATURAL GAS TECHNOLOGY DEVELOPMENT
1992 GAS-RELATED R&D INVESTMENT
(Millions of Dollars)

	Supply	Trans.	Distrib.	End Use	Total
Companies					
Producers	$222	$0	$0	$0	$222
Service Companies	113	0	0	0	113
Transmission Companies	0	1	0	0	1
Distribution Companies	0	0	9	34	43
Equipment Manufacturers	5	2	2	95	104
Subotal	**$340**	**$3**	**$11**	**$129**	**$483**
Associations					
GRI	$55	$17	$13	$81	$166
Other	0	4	1	2	7
Subtotal	**$55**	**$21**	**$14**	**$83**	**$173**
Government					
DOE	$13	$0	$0	$81	$94
Total	**$408**	**$24**	**$25**	**$293**	**$750**

the NPC. While the survey asked for expenditures to be identified as oil or gas related, due to the extreme difficulty in allocating R&D investment between oil and gas, more than 60 percent of the expenditures were reported as unallocated. The above estimate allocated these by assuming an equal distribution between oil and gas. The resulting value is similar to information developed by the GRI. The actual survey report is included in Appendix L of Volume II, Source and Supply.

The estimates for the other companies were provided by the GRI.

The data for the DOE were extracted from their report *Natural Gas Strategic Plan and Multi-Year Program Crosscut Plan FY 1993-1998*, April 1992, pages 2-3.

In 1992, most investment in the exploration and production segment of the natural gas industry was provided by private companies. When 1992 is compared with the 1988 information in the detail survey, it is clear that this has been the case for several years. Further, it is likely that it has been true for most of the industry's history. The market mechanism has proven to be very capable of providing good direction and allowing this sector to recognize the benefits of its investment. The segment has responded very strongly to these signals.

The end-use sector has received the bulk of the rest of the industry R&D investment with approximately equal contributions from the individual companies, the GRI, and the federal government. All of these segments combined, however, invest less than half the total, and it is recognized that commercialization of consumer technologies has been limited.

Natural Gas R&D Investment by Local Distribution Companies

Local distribution companies (LDCs) conduct research targeted primarily at operations

and end use. Operations research seeks to improve safety and productivity, or to otherwise lower the costs of operating and maintaining the gas distribution facilities and infrastructure owned by the LDC. End-use research is mainly targeted at maintaining or building additional gas demand for the LDC by developing improved and advanced gas utilization equipment for use by customers. These customers are also rate payers protected by a regulatory structure administered by a PUC.

The current regulatory process requires an LDC to support expense levels, including R&D, before these expenses can be included in the rates charged to consumers. Many interveners, especially those that represent residential consumers, small businesses, and large industrial customers, participate in the regulatory proceedings. These interveners, as well as the PUC, will test the purpose and level of any expenditure by attempting to measure, in some manner, the benefits accruing to their clients as a result of a utility incurring that expense. Therefore, an LDC's cost recovery is generally restricted to R&D programs that can readily demonstrate benefits to consumers.

Historically, state PUCs have accepted federally approved rate levels and have allowed LDCs to pass these costs on to their customers. Thus, the charge included in an LDC's gas cost from its gas supplier for the funding of the GRI has generally been allowed cost recovery without major debate.

Local residential consumer advocates are currently intervening and actively participating in the debate on GRI funding at the federal level. Their arguments mirror those on the state level—i.e., what are the benefits that will result to residential consumers as a result of GRI funding? If the formula is modified to allow collection by means of pipeline direct billings to LDCs or pipeline reservation surcharges, these advocates may attempt to have state public utility commissions deny pass through or recovery of the GRI charge at the state level. These advocates, and some state regulators, are opposed to any changes in the GRI funding mechanism that have the effect of reducing the amount of GRI funding from interruptible customers and increasing the burden on firm customers.

This study used focus groups consisting of representatives from 15 key industry groups, including regulators, customers, and suppliers, to define the impediments that inhibit the gas industry from increasing demand. The focus group for state public utility commissioners indicated a belief that R&D is very important to increasing demand. They support the view that GRI has done a good job of new product development, but the commercialization effort has been limited.

The focus group for state PUC staffs indicated a general view that research, development, and commercialization are essential to increasing demand, but they questioned the commitment of the industry to new products. The high initial costs of new gas-fired technologies were viewed as an impediment, and the participants suggested the industry develop a venture capital pool to handle the first-cost issue. They also indicated that the industry fragmentation and image were seen as impeding R&D efforts, particularly compared to the corresponding efforts by the electric utility industry.

In the competitive market, business owners and shareholders are able to reap the benefits of successful deployment of new technology. In contrast, traditional regulatory methods utilizing a "cost plus" rate-of-return methodology provide little reward to shareholders for vigilant economizing, constant gains in efficiency of operations, rapid adoption of new technology, bold initiatives in offering new services, or creativity in meeting the needs of customers. In this system, if investments lead to greater efficiencies (i.e., reduced costs) then allowable rates are simply lowered at the next rate proceeding so that the rate of return remains the same. Similarly, if additional market is developed, the rates are once again adjusted to bring the rate of return back to the allowed level.

It is clear from the focus group discussions with the LDCs and the PUCs that there is a basic limitation in the market communication mechanism that is required for the successful implementation of the ***fundamental premise*** for R&D investment. That is, the benefits from R&D investment should accrue to the investor. Yet in order to achieve the market demand levels projected, it is imperative that the investment in research, development, and commercialization of end-use technology be made.

The issues for the LDCs are:

Why should I (as a regulated LDC) make investments in R&D if:

1. **I and my shareholders cannot realize the benefits from the investment that reflect my risk.**
2. **I must spend time and effort in justifying the investment to the PUC for cost recovery.**
3. **My shareholders may incur additional investment risk without cost recovery.**

Ideally, these issues could be addressed through some form of incentive regulation that permits investors to make appropriate decisions about the risk and reward involved in shareholder investments in research and development.

If traditional cost-of-service regulation remains in effect, however, local distribution companies will have to embark upon a concerted effort to educate public utility commissioners and staffs about the value to consumers of LDC investments in research, development, and commercialization. LDCs must present information that shows how R&D and commercialization investments benefit customers, both by means of general outreach to the entire regulatory community and by means of presentations and advocacy before state PUCs. Also, state regulators must make an effort to better understand the potential for improvements in the price, quality, and reliability of gas service and environmental quality that can result from R&D and commercialization activities. These activities should have the cost-effective potential to:

- Increase the efficiency of natural gas end-use products
- Increase the efficiency of providing services
- Increase load factors in an environmentally and economically sound manner, thereby spreading fixed costs over higher volumes
- Substitute gas usage in lieu of forms of energy consumption that are more harmful to the environment than natural gas.

Natural Gas R&D Investment by Transmission Companies

This 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.

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 status to improve system efficiency, reliability, and response to customer needs. To ensure timely service to new customers, the integrity and reliability of the industry's pipeline and storage asset must be maintained and the capabilities of the system enhanced.

In making the transition to a gas transport system that can achieve the gas industry's goals, technology will play an increasingly important role. The goal of R&D investment in the transmission (pipeline) segment of the natural gas industry is to reduce the cost of moving gas from the wellhead to the customer and increase system performance and reliability. This includes reducing operating costs as well as capital investment requirements for new facilities. Inherent in any efforts to reduce gas transportation costs is the goal of maintaining and, if needed, improving the safety and reliability of the pipeline system.

In terms of strategic issues for the transmission and storage segment, the GRI has identified the following:

- Reduce transportation costs
- Assure deliverability of natural gas to customers
- Enhance transport system reliability
- Maintain gas transport system integrity

- Minimize the cost of compressor station emission compliance
- Assure safe and environmentally benign gas transmission system operation, maintenance, and construction.

The transmission and storage segment of the natural gas industry has a 1992 R&D budget of $22 million allocated to develop information and new technologies to meet the needs of the transmission and storage system. Two-thirds of the budget ($15 million) is managed by the GRI. The Pipeline Research Committee of the AGA conducts a $4 million research program; while manufactures of equipment used for the transmission and storage of natural gas contribute $2 million. The individual companies also conduct small programs of their own with an aggregate investment of about $1 million. These 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.

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 the GRI, begun operation of a metering research facility, and a non-destructive evaluation research facility is under construction.

The AGA, a national trade association of approximately 250 natural gas distribution and transmission companies, provides support to the Pipeline Research Committee. The committee continues to pursue a comprehensive program funded and directed by its member companies in fields related to pipeline safety, reliability, and efficiency. The research program continues the ongoing focus on reducing the ownership costs associated with pipeline design, operations, and maintenance. The current budget of $3.7 million supports some 72 individual projects with emphasis on line pipe service behavior, corrosion prevention and mitigation, in-line inspection, welding procedures, offshore operations, and improved compressor performance.

The transmission and storage segment of the industry has always been subject to regulation. Thus, it faces the same problems with respect to R&D investment as the LDC segment. However, with the direction of the transmission segment toward open access and new pricing mechanisms such as incentive pricing, new forces will be coming into play. It is not clear yet how R&D will be viewed by the companies, and particularly how they will react to funding the GRI.

It is clear that a competitive environment will make operating efficiencies much more important, and consequently, the value of R&D investment in this area.

The Gas Research Institute

The Natural Gas Industry formed the Gas Research Institute in 1976 and it received FERC approval in 1978. It was established to respond to some of the regulatory constraints and has a mission to plan and implement a coordinated, industry-wide R&D effort on behalf of the overall gas industry. It continues to be regulated by the FERC through the rate-making process that determines what each pipeline company may charge its customers for investment in the GRI, and consequently, what costs may be passed through by an LDC to rate payers. It has a budget of $166 million for 1992, and is about half the size of the Electric Power Research Institute.

The GRI R&D program is developed with input from a broad cross-section of the gas industry's technical and marketing resources. Varying levels of advisory groups provide this input from producers (both majors and independents), pipelines, distributors, and representatives of the regulatory and scientific communities. For 1992, this process resulted in a budget that is allocated with 33 percent to supply options, 47 percent to end use, 17 percent to gas operations, and 3 percent to cross-cutting projects. This distribution is not significantly different from 1990 and 1991.

Most segments of the industry and various regulatory bodies recognize GRI for doing a good job of developing and disseminating technology for all segments of the industry. Its

efforts have had significant impacts on the industry, including:

- Developing resource information, geology, and production techniques contributing to the rise of the coal seam methane gas resource
- Advancing the understanding and modeling of hydraulic fracturing in tight formations, most notably the tight gas sands in the West, leading to significant improvements in the economic recovery of gas from these resources
- Verifying the magnitude of the unrecovered resources in existing fields, and developing tools to help find the untapped compartments
- Developing the advanced heating equipment and resolution of venting and materials corrosion issues, which have contributed to the gas industry regaining its market share in residential new construction
- Establishing natural gas as the fuel of choice in commercial cooking and industrial heat treating
- Introducing the first new gas cooling technologies since the 1960s
- Introducing the first manufacturer warranted, mass-produced engines (for transit buses) and vehicle (Chrysler van) into the vehicular transportation market
- Increasing the reliability of the existing transmission and distribution system through understanding of pipe materials behavior and reducing the cost of new installations using "no dig" guided horizontal boring and advanced joining systems
- Providing substantial data to regulatory bodies leading to appropriate regulatory action (or non-action) in environmental areas and operational issues.

In addition to its role as a technology developer, the GRI serves as a focal point for other industries and organizations needing or desiring to interact with the natural gas industry on technology issues. Examples include:

- Interacting with the steel and glass industries to solve productivity, efficiency, and environmental problems
- Establishing industry-wide efforts with each of the "big three" auto manufacturers to bring natural gas vehicles to the marketplace
- Providing a forum for reaching consensus among the gas industry and appliance manufacturers on inputs to DOE on gas appliance efficiency standards
- Carrying out extensive technology transfer efforts through workshops and seminars to technology users and manufacturers.

These examples demonstrate the benefits of an industry-wide R&D function that can perform a role that is impossible for either government agencies or smaller companies to accomplish.

The major issues for the industry regarding the GRI are:

If the GRI is to be the primary developer of end-use technology and a major participant in the producing and transmission segments for technology development, how should the GRI be funded for the long term?

How can the GRI's regulatory provisions be altered to allow additional commercialization efforts?

Natural Gas R&D Investment by Producers

The supplies of natural gas projected for the two NPC scenarios depend on the continued progress in technological improvements. These improvements include not only the significant breakthroughs that change the way an industry conducts its business, but also the myriad of small improvements and the gradual adoption of these improvements by the majority of the industry participants. The industry can experience a quantum change in a particular technology with dramatic impacts on a portion of the resource base. However, when the overall results are examined, there appears generally only continuous, gradual improvements. These continued major developments are required in order to maintain the rate of improvement that has been experienced in the past.

As indicated by the data in Table 8-1, the upstream segment of the natural gas industry has in general believed that private research spurred on by a healthy business environment and supportive government policy was the most efficient approach. The competitive nature of the industry and the large amount of research effort by various segments of the petroleum industry, including E&P companies and service companies, have been seen as adequate. And this competitive, private-sector approach to the upstream side of the natural gas business has been very successful in providing today's advanced level of technology development and employment.

The technological advances by the industry have been accomplished because of a strong commitment to relatively stable, well-funded research programs, and the advances have offset the costs of harder to find and produce natural gas and increasing environmental costs associated with regulation compliance. The market mechanism has proven to be very capable of providing good information and allowing this sector to recognize the benefits of its investment.

The larger companies in petroleum exploration and production have relied on internal research programs. Recently, both larger and smaller companies have begun to rely on the Gas Research Institute for some upstream R&D support. However, the GRI has limited funds and while it does work cooperatively with DOE, it does not receive any funding directly from DOE. Consequently, the GRI is limited in the amount of upstream support it can provide.

While investment by this segment will likely continue, there is concern that the level of this activity might be adversely impacted by the current economic conditions, especially natural gas prices, and the industry downsizings. A survey of upstream R&D expenditures was conducted for this study and is included in the Appendices of Volume II, Source and Supply. An analysis of this survey drew the following conclusions:

- R&D expenditures between 1988 and those planned for 1992 held steady. This conclusion may be misleading because many of the reductions in R&D expenditures may not become apparent in company budgets until later this year or in planned expenditures for the next year. Respondents indicated, however, that 1992 data were current budgeted values and not estimates made in 1991. At the end of this year, the full effect of recent downsizing might be empirically evident.
- There is no demonstrable shift to collaborative research, as was expected in 1988. This is logical, since companies would preferentially fund their own staff before spending money on outside R&D operations, unless R&D expenditures were increasing.
- Company priorities for federal R&D are consistent among operator and service sectors of the industry. Companies feel that federal research should focus on environmental technologies and reservoir evaluation/characterization and minimize involvement in drilling and production technology research.

The issues facing the upstream segment of the natural gas industry are:

With the majors undergoing restructuring programs and focusing their investment programs on international operations, will adequate investment in natural gas supply related R&D continue?

With the independent sector growing its share of domestic natural gas production, how can technology transfer programs be enhanced to ensure the continued technology advancement?

The Federal Government and Natural Gas R&D

Over the past 13 years, the budget for the Fossil Energy Office of the Department of Energy budget has varied between $273 million and $1,119 million (see Table 8-2). The percentage of funds allocated to natural gas has varied between 2 and 6 percent of the total. Coal research has dominated the program quite consistently for more than a decade, consuming 85 or 90 percent of the fossil energy research funding. This is in part an artifact of the

TABLE 8–2

DEPARTMENT OF ENERGY—OFFICE OF FOSSIL ENERGY
ENERGY RESEARCH AND DEVELOPMENT EXPENDITURES
(Millions of Dollars)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Coal													
Control Tech & Coal Prep.	$38	$37	$22	$28	$26	$35	$33	$38	$42	$49	$58	$56	$51
Adv Res & Tech. Dev.	56	58	56	36	46	40	35	32	32	27	27	31	30
Coal Liquefaction	250	521	99	38	29	26	33	24	27	32	35	43	39
Combustion Systems	51	57	31	24	18	30	30	15	22	27	34	37	38
Fuel Cells	26	32	34	30	43	41	35	28	33	27	39	43	51
Heat Engines	50	36	15	5	6	12	13	12	18	23	21	24	18
Underground Coal Gasif.	10	10	8	6	6	6	4	2	3	1	1	1	0
Magnetohydrodynamics	75	67	22	29	30	31	29	26	35	37	41	40	40
Mining R&D	69	49	14										
Surface Coal Gasification	116	165	53	39	36	32	43	25	23	22	24	15	11
Clean Coal							99	149	199	190	554	391	465
Total Coal	**$741**	**$1,032**	**$354**	**$235**	**$240**	**$253**	**$354**	**$351**	**$434**	**$435**	**$834**	**$681**	**$743**
Oil													
Advanced Process Tech	6	4	4	5	5	5	6	4	3	4	4	10	14
Enhanced Oil Recovery	23	19	16	7	9	12	12	11	17	24	28	32	37
Oil Shale	28	33	19	12	16	15	13	11	10	11	9	17	6
Total Oil	**$57**	**$56**	**$39**	**$24**	**$30**	**$32**	**$31**	**$26**	**$30**	**$39**	**$41**	**$59**	**$57**
Total Gas	**$35**	**$31**	**$9**	**$14**	**$16**	**$10**	**$9**	**$8**	**$11**	**$11**	**$15**	**$16**	**$13**
Grand Total	**$833**	**$1,119**	**$402**	**$273**	**$286**	**$295**	**$394**	**$385**	**$475**	**$485**	**$890**	**$756**	**$813**
Percent Coal	89%	92%	88%	86%	84%	86%	90%	91%	91%	90%	94%	90%	91%
Percent Gas	4%	3%	2%	5%	6%	3%	2%	2%	2%	2%	2%	2%	2%

old, incorrect perception that coal was an abundant domestic resource and natural gas was not.

The natural gas resource base is now recognized as able to support a much larger share of U.S. energy demand than was previously believed. Coal is no longer the only abundant domestic fossil fuel.

DOE Research Is Changing

The DOE is working on new ways to sponsor cooperative research. The DOE wants companies to have a stronger role, through their own joint support, in the selection and conduct of the research. These recent efforts have become more effective in guaranteeing relevancy by requiring industry participation, and jointly funding projects with existing industry research consortia and organizations such as the GRI.

Potential for Significant Breakthroughs

Most gas has been discovered as a result of looking for oil. Focusing on gas is a relatively new activity, so research is still likely to produce important results. Numerous studies, including this NPC study, present important topics for further gas research, such as reservoir characterization. Furthermore, research on gas will help exploration and production of oil as we work with an increasingly mature domestic resource base.

Transfer of Technology Throughout Industry

Government can help facilitate the transfer of technology as well as help advance technology development. The full impact of a technological development can only be realized when it has been applied to all appropriate resources in the industry. To achieve this, the technology must be transferred to the members of the industry. One way the government, in cooperation with industry and established industry associations, can assist in this transfer of technology is through project and workshop sponsorship.

Dialogue will continue between the government and the natural gas industry over regulation, access, and fiscal issues. Cooperative research will help establish ties and trust that can lead to solutions that are better for both parties and hence help ensure a stable future energy supply. Joint research is likely to be an improvement over government research conducted with little industry participation, and lead to better project selection.

COMMERCIALIZATION ISSUE

The ultimate goal of most R&D investment is to develop products and services that are commercially successful. Without this commercialization, there will be no benefit to any of the segments. The real question is: Why has the natural gas industry experienced difficulties in carrying out the process of commercialization?

This question can be addressed differently for production and end-use R&D. For production R&D, the traditional approach of relying on the individual companies has proven very successful, and can be expected to continue to be effective. This is because the industry segment that invests in the R&D is also a primary beneficiary.

Even in this supply segment, however, the support of R&D efforts by government and industry organizations, like the GRI, becomes important when non-traditional resources or approaches are needed. Examples have included research on substitute supplies and on nonconventional resources. A special case also exists with regard to the many independent producers who are a vital element of the gas industry. Most of these companies simply do not have financial resources to undertake a significant R&D program on an individual basis. They obtain current technology through existing industry associations (like the Society of Petroleum Engineers), consultants, service companies, the GRI, and government-sponsored projects.

The funding for end-use R&D and its ultimate commercialization has been a long-standing issue within the industry. History has shown that the industry simply cannot rely on the end-use equipment manufacturers to advance the technology needed for gas to remain competitive. While many reasons have been set forth for this phenomenon, the most compelling is the observation that these manufacturers are generally fuel neutral. This is because they manufacture different models of the

same appliances and equipment to use either gas, oil, or electricity. A heating or cooling system manufacturer has no profit incentive to develop and sell a piece of gas-fired equipment versus one fueled by another energy source.

This statement must be tempered by a view of customer demand, which does create market share advantages for one fuel source versus another. Nonetheless, no U.S. manufacturer rushed to fill the gap in the 1970s when electric cooling technology rapidly outpaced the existing single-effect gas cooling systems, despite the general satisfaction of customers with gas cooling. Similarly, it would be difficult to find the motivation for the U.S. auto makers to develop natural gas vehicles on a purely profit-based decision.

The industrial process area in general provides several additional examples. Natural gas is the dominant energy used by several heat process industries. This is because natural gas effectively provides the heat requirements and is reliable, efficient, and relatively low cost. However, heat processing technology is improving and quality issues have become a major driver for material production. In addition, environmental concerns (e.g., exhaust emissions) have also created a need for new heating process designs. Since either of these issues can result in a switch from natural gas to other heating methods (i.e., electric), industry R&D for new technologies is needed to retain these markets. With a strong market thrust defined, the industry will provide the funds needed to design and field test a new industrial process technology. Sometimes, the GRI is involved while in other cases interested (and affected) companies support the efforts.

The end result of the R&D is a new technology ready for a plant site demonstration. It is now up to the equipment manufacturer to market the technology, including a first-in-the-field demonstration. The trail of failures from this approach is long and discouraging. Currently, new natural gas-fired technologies such as a vacuum furnace (for ion-nitrariding), a mineral wool melter, a glass cullet preheater, high temperature heat treating furnaces, engine drive chiller technologies, and a secondary aluminum melter are examples of technologies not exploited by industry and on very slow commercialization tracks.

Another example outside the industrial process area is fuel cell technologies. Without going into the litany of commercialization hurdles facing these technologies, suffice it to say the available funding will significantly slow the availability of commercial equipment. In fact, it is likely that some promising technologies will not survive due to R&D funding constraints.

As the process size and complexity increase, the ability to assemble the needed R&D funds becomes increasingly difficult. The GRI's program to develop and field test an Advanced Glass Melter, for instance, will require a major portion of their entire non-metals R&D budget even with cofunding matching that amount.

Probably the most significant failure in commercialization efforts in general is the failure of the companies involved to use their own technological developments. After technology is developed in the research facility, it needs a pilot location for demonstration of the first attempts at commercialization units. In the producing sector, this is often a particular field or well. And the industry has been very successful in providing the opportunities for these pilots.

However, the end-use products are more likely manufactured by a company outside the direct gas industry. Here the companies in the natural gas industry have provided very few opportunities in their own operations and facilities for these initial commercialization efforts. Even now, there continues to be very limited use of natural gas fueled vehicles in the companies' fleets and natural gas cooling in their facilities. If the companies in the industry do not recognize the benefits of the technology, how can the marketing organizations be expected to achieve very much market penetration?

The issue of commercialization is critical to all parties.

Consequently, what incentives can be created to enhance investment in commercialization when the benefits are limited for the regulated segments of the industry?

CHAPTER NINE
RELIABILITY

OVERVIEW

The National Petroleum Council identified the importance of the reliability issue early in the study process. The study participants found that reliability cannot be readily defined in that it embodies a variety of perceptions and myths, as well as facts and analysis by all industry sectors. Due to the complex nature of the reliability issue, the NPC has relied on the focus group process to help define reliability and summarize the problem that this issue creates.

The focus group analysis included in Volume V, Regulatory and Policy Issues, identifies improving reliability as one of the major challenges facing the natural gas industry. Thus, the reliability theme can consistently be detected throughout the study. As the natural gas industry moves forward, it must address the reliability issue head on to ensure that natural gas is best able to play a role in the nation's future energy needs.

RELIABILITY—COMMON THEMES

While many customers have their own individual perspectives, there are some themes on natural gas reliability that seem to cross virtually all market segments. The focus group report summarizes these themes as discussed below.

Supply Deliverability

Simply stated, commentors expressed a concern that adequate wellhead supply will not be available to meet consumer needs. These concerns do not seem to be related to the adequacy of the natural gas resource base to meet consumption requirements, but more a concern as to whether the industry producers will invest in and maintain adequate deliverability levels to meet future natural gas demand. This concern is supported by historical evidence of actual shortages experienced during the 1970s. Further, commentors question whether current price levels are adequate to maintain drilling activity, as well as keep investment dollars for domestic exploration. In addition, the prorationing issue as it has been raised in the states of Oklahoma, Louisiana, and Texas adds to the uncertainty as to the adequacy of supply availability.

Pipeline Deliverability

Like supply deliverability, this concern has also been supported with the actual experience during the 1970s, as well as more recent experience with pipeline capacity problems, including the lack of available firm transportation and the seasonal interruption of interruptible transportation. There is also concern with pipeline operating procedures and whether these procedures will allow for a consistently reliable level of pipeline service. These concerns with pipeline deliverability extend to the expansion of pipeline capacity with some focus group participants being concerned over whether incremental pricing of expansion capacity will allow the capacity to be constructed.

Regulatory Environment

The current regulatory environment causes concern as to whether regulators will allocate gas supply away from both electric utilities and industrial consumers in future supply shortage situations. Historical changes in the regulatory policy toward contractual obligations further add to the concerns. In addition, there seems to be some concern about the implementation of open-access programs permitting all potential customers of gas to have the opportunity to acquire both transmission and storage capacity to meet their needs in the future.

Price Volatility

Focus group participants are concerned about price volatility, and whether natural gas will be competitive with alternative fuels in the future. The concern about price volatility has been supported by significant swings in the price of spot gas, as well as a perception that there is a lack of willingness by some participants in the industry to enter into long-term contracts.

Marketing Companies

Some focus group participants perceive the marketing company as existing only to make a quick dollar and as being unreliable.

RELIABILITY CONCERNS BY CUSTOMER GROUP

As expected, virtually all customer groups involved in the study indicate that reliability concerns have some impact in making their fuel choices. Each group has a unique view of reliability, however, thus creating a need to outline these concerns as they relate to each customer class.

Residential/Commercial

The focus group comments from consumer advocates for the residential and commercial consumers identify concerns regarding safety, service interruptions, and maintaining a stable competitive price. This group expressed the concern that spikes in gas prices undermine captive customers' confidence in natural gas as a fuel source.

Industrial

The industrial sector, some (but not all) of which has alternative fuel capability, also expresses a concern with industry reliability. They are of the opinion that the natural gas industry cannot dependably identify the type and length of service interruptions that they might likely face. Industrial consumer concerns are primarily focused in three areas. First, this consuming sector bases its opinion regarding reliability on the historical inability to contract supplies during the shortages of the 1970s. The industrials also express concern about the cost of firm transportation service, and thus rely on interruptible service, which they characterize as unreliable. Finally, industrial consumers fear, even though they may have contracts for firm service, curtailments in emergency situations.

Electric Utility

Reliability is also noted as the most important concern of the electric utility participants. Those utilities, which use natural gas to serve their peaking needs, are concerned with the industry's ability to meet hourly swings and the pressure requirements of combustion turbines. Therefore, deliverability, not supply availability, is the primary thrust of their concerns. The pipeline's historical requirements of 24-hour notice for deliveries is perceived by some utilities as not providing reliable, customer-oriented services.

Independent Power Producers

Independent power producers express concern with whether pipelines will build new facilities to meet their gas requirements on a timely basis. Independent power producers also question supply deliverability. They believe that the present wellhead prices are too low to encourage drilling, which they fear may result in supply disruptions.

SUMMARY OF RELIABILITY ISSUES

Physical Aspects of the Reliability Issue

There are several dimensions to the reliability issue that are factual or "physical" in nature. These include the adequacy of the re-

source base, the current deliverability, the ability of the delivery system to meet market requirements, the availability of capacity to meet new market requirements and serve specific geographic areas, and the willingness of the industry to add capacity to eliminate bottlenecks.

Contractual/Regulatory Aspects of the Reliability Issue

The gas industry's ability to provide reliable service has also been undermined by contracts unresponsive to changing market requirements, constantly changing regulation, and the lack of easily understood service reliability standards. This issue is extremely complex, but in a nutshell, the industry needs to be able to write contracts that will respond to changing market conditions and be honored by all parties and not be abrogated by regulatory action. Also, through the use of more easily understood reliability standards, the industry ideally will be able to offer products that will be able to compete with alternative energy sources.

Perceptual Aspects of the Reliability Issue

> Nowhere is the statement "perception is reality" more descriptive than when discussing the role that reliability concerns play in shaping attitudes toward natural gas consumption. Virtually all of the demand groups state succinctly that reliability problems plague the industry.

The above comment mentioned in the focus group report identifies perhaps the most difficult aspect of the reliability issue that the industry must address, and that is the perception that natural gas is unreliable. Natural gas marketing programs, while outlining the economic and environmental advantages of this fossil fuel, need to also provide factual and informational reassurance regarding the reliability of this fuel source.

RECENT EFFORTS TO ADDRESS RELIABILITY ISSUES

Natural gas industry participants as well as regulators have taken several specific actions over the past few years in attempt to address reliability issues. These actions include: the FERC/DOE Deliverability Task Force; the Interstate Natural Gas Association's Power Generation Task Force; FERC Order 636, which has emphasized maintaining operational integrity of the pipeline systems; as well as the development of financial risk management markets, which provide a means to address the price volatility aspect of reliability. In addition to these efforts, the Natural Gas Council has identified reliability issues as being a key to increasing natural gas demand and has initiated a scoping study on the need for a Natural Gas Reliability Council. These and other efforts to address the reliability issue should continue to be supported by industry.

COMPARISON TO OTHER RELIABILITY ORGANIZATIONS

In addition to the above mentioned efforts to address the reliability issue, the natural gas industry may also want to look to other groups that are making efforts to address reliability, namely the Voluntary Allocation Committee, the Network Reliability Council, and the North American Electric Reliability Council.

First, about 10 to 15 years ago the Texas Railroad Commission established an informal group called the Voluntary Allocation Committee, which is aimed at planning for gas supplies under stress situations. This committee consists of about 12 members from various areas of the state including intrastate pipelines and electric utilities. The group will typically meet once or twice a year: once, to discuss general conditions for the coming winter, as well as a conference call meeting during periods of stress.

The Network Reliability Council was formed by the Federal Communications Commission in December 1991 to respond to a public outcry over telephone outages. This group consists of 33 people representing telephone management, unions, state regulators, and consumer groups. The Council is a federal advisory committee formed to provide: expert technical advice to the FCC and to the telecommunications industry on issues related to telephone network reliability; a mechanism to facilitate within the industry the higher level of communication that deployment of new technologies requires; and a focused look from the

industry on issues that arise because of increasing network interdependence.

And finally, the North American Electric Reliability Council was formed in 1968 by electric utilities to coordinate, promote, and communicate about the reliability of their generation and transmission systems. It is comprised of nine regional councils and one affiliate that together encompass virtually all of the electric utility systems in the United States, Canada, and the northern portion of Baja California, Mexico.[1]

RELIABILITY RECOMMENDATIONS

In addition to the efforts undertaken to date, the subsequent volumes of this report make specific recommendations that will help address reliability issues. The following is a summary of these recommendations.

Volume II: Source & Supply

The Source and Supply volume recommends that both state and federal policy makers adopt practices that reestablish confidence of buyer and seller alike in the sanctity of contracts by reducing the exposure to retroactive changes and unreasonable "prudency reviews" in order to alleviate reliability concerns related to contracting.

Volume III: Demand & Distribution

The Demand and Distribution volume identifies reliability concerns as obstacles to increased gas consumption and therefore recommends that the industry:

- Demonstrate to certain customer segments, especially industrial and electric utilities, that natural gas is a reliable source of energy today and in the future
- Enhance cooperative reliability and thereby eliminate the general customer perception of some customers that the use of natural gas is too risky

Volume IV: Transmission & Storage

The Transmission and Storage volume recommends that the industry expand its work with customers to identify and address specific reliability concerns. While the industry has been making a significant effort to address reliability concerns and to develop operating guidelines, significant progress remains to be made. Accordingly, this recommendation is expanded in Volume IV as follows:

Industry should:

- Consider the formation of a national voluntary organization to assist in periods of operating stress
- Create an industry master contact list for 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
- Improve communication on electric generation issues.

Federal, state, and local officials should:

- Support the industry's efforts to address reliability concerns and to develop operating guidelines that improve the overall quality of service to natural gas consumers, including addressing any potential conflicts between the regulatory framework and contracts

Volume V: Regulatory & Policy Issues

The first recommendation of the regulatory and policy issues volume regarding reliability is that regulators should not interfere with the consequences of choices made by buyers and sellers of energy services. In addition, the recommendation with regard to prorationing—which was defined as a reliability issue—is that producers should be left with the maximum possible discretion to manage their production in relation to swings in market demand and prices.

POTENTIAL ROLE OF A SPECIFIC ORGANIZATION DEDICATED TO ADDRESSING RELIABILITY ISSUES

The NPC believes the industry should give serious consideration to the formation of a Natural Gas Reliability Council and therefore supports the ongoing efforts to study this issue. The

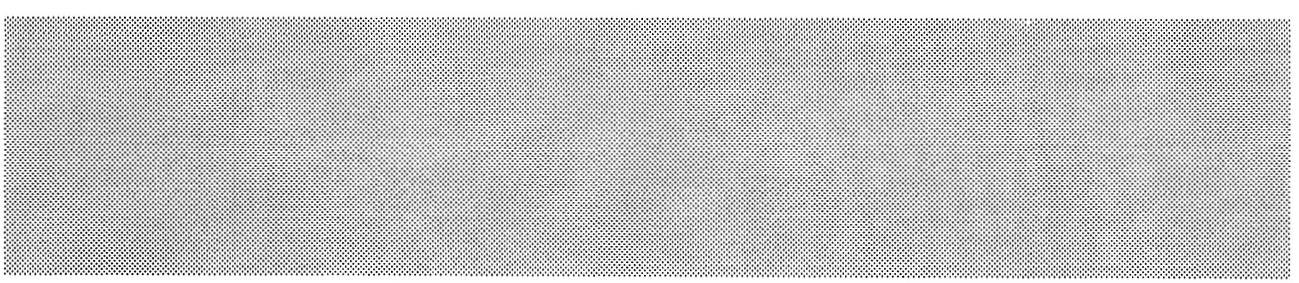
[1] North American Electric Reliability Council, *Reliability Assessment 1992-2000*, "The Future of Bulk Electric Supply in North America," September 1992.

Council's purpose would be to increase customer confidence in the reliability of natural gas service and its mission would be to provide the facts and analysis relevant to the reliability of natural gas service. This organization would be a reliable source of information for all customers and industry participants, and could have many possible tasks including the following:

1. The organization could help to develop a uniform and easily understood set of standards, as well as a vocabulary for reliability. As an example, the industry does not currently have a consistent definition of deliverability available from wellheads, pipelines, and local distribution companies. This organization could help support the implementation of electronic data interchange, could develop information guidelines, and could review, develop, and disseminate data.
2. This organization could play a significant role in planning and coordinating peak periods in emergencies to help respond to the questions that come up in that area, such as "if December 1989 happened again, then would the industry be able to respond?"
3. This organization could undertake to improve coordination of maintenance and downtime across industry segments.
4. This organization could help to identify specific reliability needs of end users and to help develop ways to address these needs. An example of some questions that could come up would be, "would gas be available to serve my project 5, 10, 15 years from now and can natural gas serve the highly variable loads of my combustion turbine that I wish to locate on this site?"
5. This organization might as it undertook this analysis generate specific recommendations to improve reliability that would otherwise not be made absent taking a broad industry perspective.
6. Perhaps, most importantly, this organization would represent a very significant commitment on the part of the industry to address the reliability issue and, as a result, show potential end users of natural gas that the industry was concerned about reliability and was going to do something to improve the reliability of natural gas service.

Overall Study Recommendation

The NPC believes that a comprehensive study involving all sectors of the industry should be conducted to determine whether there is a need to establish a specific organization aimed at addressing the reliability issue. This study should further identify the goals of a reliability council as well as a plan for implementation. In addition, the study should address antitrust concerns, regulatory issues, as well as the cost of developing and administering such an organization. The Natural Gas Council has begun such a study and the NPC supports their ongoing efforts.



CHAPTER TEN
CONTRACT DIVERSITY

OVERVIEW

This chapter discusses the importance of contracts in the future natural gas industry, and the specific techniques being used in the industry, including financial risk management, to serve customer needs. These techniques as well as the history surrounding the contracting issue are more fully discussed in Volume II, Source and Supply. The NPC has developed specific recommendations in the area of contract diversity.

Today's natural gas industry is incredibly diverse, particularly when compared to the industry's historical relationships. There are over 5,000 independents and major producers, over 80 interstate pipelines, and over 150 intrastate pipelines. Nationwide, an estimated 1,400 local distribution companies (LDCs) serve 4 million commercial customers and tens of millions of residential customers. There are also at least 275,000 industrial end users of gas. These industrial users consume 17 percent of the gas as feedstock, 32 percent as boiler fuel, and 51 percent for process heat. Industrials also have 1,600 cogeneration projects, which consume natural gas. Other independent electric power producers that consume gas for baseload and peaking needs number almost 4,000. In the United States there are approximately 3,500 electric utilities that utilize natural gas for 9.5 percent of their generation needs.

Due to the diversity in the industry participants, generalizations about the contract needs of any segment of the industry can be misleading, or simply incorrect. Each buyer and each seller has a unique set of requirements, preferences, and objectives that can be matched by the efficient operation of an unregulated, unbiased market for the sale and purchase of natural gas.

Today, natural gas contracts must be designed to accommodate the diverse production, consumption, transportation, and pricing needs of an industry in transition. As the deregulated gas sales, transportation, and other natural gas service markets continue to mature, the trend is toward more contract options and flexibility.

FOCUS GROUP COMMENTS ON CONTRACTING ISSUES

The focus group comments with regard to this issue fall basically into two categories, service and regulatory concerns. These specific concerns will be further detailed below.

Service Issues

Service options are becoming increasingly more valuable to end users, as exhibited by the emergence of natural gas service companies. However, the focus group participants noted that customers have not obtained the services that they want and to which they attribute value above the value inherent in the commodity.

One industrial customer noted that in order to adequately make energy decisions they needed:

> the ability to have reliable resources available to us—the ability to enter into a gas contract with alternate suppliers; the ability to have control of the capacity of the pipeline, both at the interstate and the local utility level [so that we can] get the commodity that we're entering into contracts with producers to our burnertips. If we're not allowed into that process, we're going to find ourselves at the short end of the stick.

An independent power producer (IPP) noted that in order to obtain financing they must be able to demonstrate to their financiers the reliability and stability of their fuel supply and cost. This requires that they obtain long-term contracts with fixed or highly predictable and stable fuel prices. Past difficulty in obtaining these types of contracts has inhibited use of natural gas for their facilities. Recent evidence that suppliers are more willing to meet these needs encourages the participants to believe that natural gas will be a more viable alternative in the future.

Regulatory Issues

The uncertainty of the regulatory process in which the gas industry functions is another major source of perception that the industry is unreliable. Participants mention that actions including open-ended prudency reviews and regulators' failure to respect the sanctity of contracts causes uncertainty and raises the prospect of reliability. Virtually all industry participants along the gas chain concur that the regulatory bodies should honor the sanctity of contracts. The uncertainty with regard to contracts tends to interfere with the market processes such that projects cannot be financed, and business relationships are disrupted. One IPP customer noted:

> But my feeling is wherever you have contracts in place, whether they be a contract with your company to move gas or [with] an LDC throughout the term of that service agreement, you have to respect those contracts, because without the contracts, you will have disorder. Projects can't be financed. So, my feeling is the FERC can't interfere with existing arrangements. But once existing arrangements terminate, you will have to effectively deregulate them with open access and unbundled services and costs.

RECENT EVOLUTION OF CONTRACTS

As the natural gas market is moved to a lesser reliance on regulation, innovative contracts are being employed to provide an increasing number of choices for gas customers. These increasingly diverse contracts include services provided by both regulated and unregulated players in the natural gas business. Ten years ago it was very difficult, if not impossible, for a customer to arrange for a discounted rate with pipelines. Today, virtually all pipelines have the opportunity to discount their transportation rates between minimum and maximum rates at the federal level. At the state level, many state commissions permit distributors to charge flexible sales and transportation rates, particularly to the extent that the lower rate charged allows natural gas loads to stay on the system instead of being lost to an alternative fuel. This flexibility in the regulated world has allowed natural gas to stay very competitive with alternative fuels, notably fuel oil, during the past five years.

On the deregulated side, producers have also been able to sell gas on increasingly flexible and diverse terms. Since prices for the most part are no longer regulated at the wellhead, producers are now able to offer a significant number of choices to their customers, selling gas on both an interruptible and firm basis, selling gas tied to indices for gas prices, as well as selling gas tied to alternative fuels. A new industry segment, gas marketers, has also developed over the past ten years. This segment is focused on aggregating supplies and offering these supplies to markets based on their unique characteristics.

Yet another area of natural gas service available to customers now that was not available ten years ago involves the packaging of specific natural gas services for customers. This includes the emergence of natural gas fired IPP projects where developers will offer to sell electricity at competitive rates; the devel-

oper effectively packages the gas supply and gas transportation along with the gas-fired equipment into one service for an electric utility or other users of electrical service. Some companies have taken a similar approach in trying to develop the natural gas vehicle business in many areas of the country.

In addition to each industry segment providing various service options, a new role within the industry has emerged over the past ten years for "natural gas service providers." This is broadly defined to include an array of companies that are moving beyond their traditional roles and providing a wide variety of customized services aimed at meeting customers' specific needs. The development of this natural gas service industry segment is a significant development for the natural gas industry, and its ability to enter into a variety of contracts is a key element of making this segment a vital part of the industry in the future.

Another significant new aspect of the developing natural gas industry is the development of new markets to support and increase service and contract diversity. Perhaps the most significant new market to develop over the past ten years has been the futures market. This is a part of a general market for financial risk management services. Specifically, this market allows parties involved in the natural gas business to manage their financial exposure to changes in natural gas prices through the use of futures, swaps, and other tools. It is expected with the advent and implementation of FERC Order 636 that similar markets may develop for both transportation and storage capacity. The NPC believes that the development of a vibrant market for services of this type is a key for the successful development of natural gas use in the future.

REGULATION AND CONTRACTS

In today's market environment there exists a tension between regulation and contracts. On the one hand, the best way to assure that the natural gas markets work in the future is to assure that contracts work (i.e., they are considered enforceable and both parties expect to gain or lose from the consequences of the contracts that they enter into). Unfortunately, the natural gas industry has a history of regulators and government becoming involved in the process when contracts do not work.

The industry has a long history (the details of which will not be included in this section), which includes the Natural Gas Act, the *Phillips* decision of 1954, and the Natural Gas Policy Act of 1978, to mention a few of the key examples of regulatory intervention in the past.

Without debating the various pros and cons of historical regulation, the NPC does believe that if contracts are made to work in the future, further regulatory intervention will be less necessary, which should accrue to the benefit of all participants in the gas industry, and their customers.

CONTRACT DIVERSITY RECOMMENDATIONS

Recommendation #1

Education of industry participants, and federal, state, and local regulators, about the natural gas market, financial risk management, and other dimensions of the new natural gas industry.

The NPC believes that a significant education effort is necessary to inform not only industry participants, but the existing and potential natural gas consumers as well, on the range of choices available in the natural gas market. This education should allow the buyer, seller, and regulator to become familiar with contracts and the contracting process, and more importantly allow them to live with the consequences of their contractual commitments. The NPC is hopeful that this more complete understanding of contracting will cause regulators to avoid intervention into contracts on an after-the-fact basis and allow for the market to work.

Recommendation #2

Reduction in regulation to the minimum necessary to protect public interest, and support of the market's evolution toward contract diversity

The right of buyers and sellers to match their individual interests is the key to optimum market performance. Contract diversity unencumbered by the uncertainty of regulatory hindsight will allow buyers and sellers alike to match their individual needs for price, term, security, load flexibility, and reliability. The state and federal governments can support the

natural gas industry by providing a regulatory environment that encourages sellers and buyers to explore possibilities of using a variety of contracts, the futures market, or other tools to help manage their businesses. Finally, as the industry develops the ability to offer a variety of gas contracts, customers' current needs will be met and they will have confidence that natural gas will be a competitive energy source in the future.

Recommendation #3

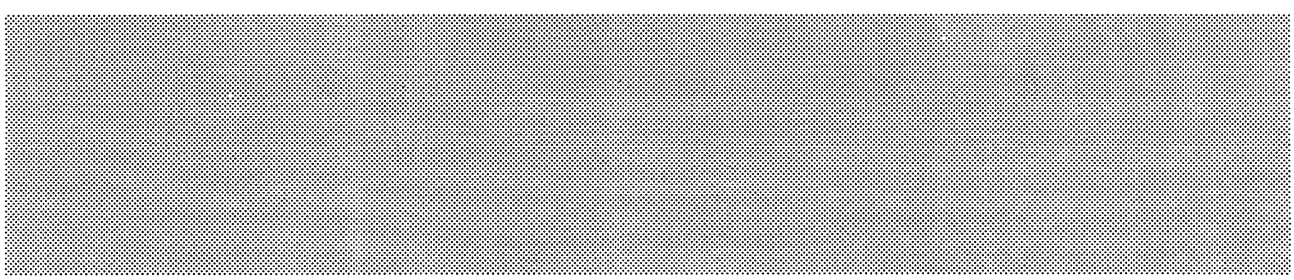
Recognition and support of the new role of natural gas service providers

The support of the new role of natural gas service providers is consistent with the overall notion of allowing market forces to dictate the direction and shape of the natural gas industry and the services that it provides. These service providers are broadly defined as an array of companies within the natural gas industry, which are moving beyond their traditional roles and providing a new variety of customized services aimed at meeting customers' specific needs. Natural gas service providers should be recognized as a vital element to the natural gas industry in that they provide the customer with the benefit of adding value to the natural gas commodity through diversified service options. As we move forward, the services that these companies provide can contribute to the overall market growth by offering options, flexibility, and reliability designed to fit the needs of specific natural gas customers.

Recommendation #4

Encourage the Development of Emerging Markets (financial, transportation, and others)

As the move continues to a more market driven environment, the need for diversified markets for financial risk management of supplies, pipeline capacity, storage, and other services is emerging. (A discussion of financial risk management techniques for the natural gas industry follows as an attachment to this chapter.) Also emerging will be a secondary market for transportation and storage capacity due to FERC Order 636 requirements. These arising markets will again add to the portfolio of options that industry participants as well as their customers will have in meeting their operational, price, and risk requirements. This variety of options can only help to stimulate growth for the natural gas industry for years to come.



ATTACHMENT

FINANCIAL RISK MANAGEMENT TECHNIQUES IN THE NATURAL GAS INDUSTRY

The Natural Gas Policy Act of 1978 began the process of deregulating the interstate natural gas industry. Until then regulation had created an environment of stable, below market-level wellhead prices with the dominant form of contracting between producers, pipelines, LDCs, and end users being fixed-price long-term contracts.

Today the natural gas industry is characterized by a nationally integrated spot market on which participants make a significant share of purchases. Gas spot prices vary daily and seasonally according to various international, national, and local events affecting the energy sector. As a result, natural gas spot prices are volatile (estimated to be around 20 percent per annum) and make future planning difficult for all participants in the gas industry.

In response to the growing need for tools to manage gas price risks, financial institutions and marketers have developed or are developing several financial risk management instruments. This essay explains the basic workings of such instruments. While the discussion is general, examples are provided to illustrate actual or potential uses of these tools in the gas industry.

Before discussing the instruments, we define some commonly used finance terms.

- ***Hedging:*** Industry participants and financial institutions utilize hedging in order to offset various business risks. Some of the common risks hedged are currency risk, interest rate risk, commodity price risk, and supply risk. The risk management tools might be financial ones like forwards, futures, options, and swaps or they may be physical ones like storage and reserves.
- ***Long position:*** When an investor buys an asset, he or she is said to have a long position in the asset. Similarly, a long futures position signifies ownership of a futures contract.
- ***Short position:*** This is the inverse of the long position. When an investor sells an asset, he or she is said to have a short position in the asset. As with assets, so also with futures.

Forwards

A forward contract is a contract to buy or sell an asset at a certain price at a certain point in the future. The price at which the parties agree to exchange the asset on expiration of the contract is called the delivery price.

In order to be a fair exchange, the ex ante value of the contract to both parties must be zero. The delivery price that makes the contractual agreement fair is called the forward price. At the start of the contract, the delivery price and forward price should be equal. However, as time passes, the forward price will usually differ from the delivery price.

While financial institutions sell currency forwards and interest rate forwards, there are no natural gas forwards sold by the same institutions. However, a fixed-price long-term contract can be considered to be a series of forward contracts.[1] Once this is recognized, pricing such a contract becomes a matter of applying the formula for pricing a forward contract.

Fixed-price long-term contracts can be used for hedging purposes as they allow the buyer and seller to lock into prices and supply in advance. This makes planning easier as the future cash flows are known in advance. However, such contracts are inflexible because although they protect the parties against adverse price moves, they do not allow the parties to take advantage of favorable price moves. The opportunity cost for regulated utilities can be especially high when regulators conduct prudence reviews of the utilities' gas purchases. In order to hedge such losses on fixed-price contracts, the parties could use futures markets. Alternatively, they could use flexible long-term contracts using the futures prices as references.[2]

[1] Strictly speaking, most of the natural gas spot contracts can be classified as 30-day forward contracts if one conceptually considers the seller to deliver all the gas at the end of the 30-day period at the price agreed upon during bid week.

[2] For an elaboration of advantages of long-term contracts in today's natural gas industry and using finance theory to price and design long-term contracts, see Sanjoy Chatterjee, *Long-Term Natural Gas Contracting with Electric Utilities:* Rationales, Innovations and Pricing, Policy Analysis Exercise, John F. Kennedy School of Government, Harvard University, April 1992.

Futures

A futures contract is similar to a forward contract—two parties agree to exchange an asset at a certain price at a certain future date. However, futures differ from forwards in that the former are standardized contracts sold on organized exchanges. The exchange specifies product quality, delivery periods, delivery points, etc. (Table 10-1 lists the specifications of the New York Mercantile Exchange [NYMEX] natural gas futures contract introduced on April 3, 1990.) Forwards, on the other hand, are customized contracts negotiated between the two contracting parties.

Actual delivery of the asset under futures contracts occurs in under 5 percent of futures transactions. Usually a participant enters into an offsetting futures contract with the same delivery month as the original futures contract and thus closes out the original position prior to maturity.

The NYMEX natural gas futures market has been successful since its inception. As of April 30, 1992, NYMEX reported an open interest in over 36,000 contracts. Marketers and producers accounted for the majority of positions, with shares of 54.7 and 16.1 percent, respectively.

As illustrated below, futures can be used to hedge either the asset itself or a forward contract.

- ***Example 3.1:*** A producer can lock into a current favorable spot price for gas that is inventoried by selling natural gas futures contracts that expire approximately at the same time as when the producer expects to sell the gas. At maturity, if the spot price for gas is lower than the delivery price, losses on the sale of inventoried gas will be offset by gains made on the futures transaction.
- ***Example 3.2:*** A utility has contracted to purchase gas at a fixed price at the end of 6 months. Thus, the utility has a long position in gas. In order to lock in the price and hedge against a drop in the price of gas, it will sell a similar quantity of natural gas futures at the same price (i.e., assume an equal short position). At the end of 6 months, any gains/losses on the actual gas purchase will be offset by losses/gains on the futures transaction. (The utility would have to obtain regulatory assurances that gains and losses on futures transactions would be treated equally.)

It must be noted that hedging with futures poses some risks of its own:

- ***Basis risk:*** The hedges described above are perfect hedges where losses and gains completely cancel each other out. Such hedges rarely occur in practice. For example, in the gas industry there is a differential between the NYMEX gas futures

TABLE 10-1

SELECT FEATURES OF NYMEX NATURAL GAS FUTURES CONTRACT

Contract Size	10,000 MMBTU (million British thermal units)
Minimum Price Fluctuation	$0.001/MMBTU
Maximum Daily Limit	$0.10/MMBTU. During the month preceding delivery there is no limit.
Trading Horizon	18 consecutive future months
Last Trading Day	Close of business six business days prior to first calendar day of the delivery month.
Delivery	Henry Hub (Sabine Pipeline Company) in Louisiana. Hub fee is paid by the seller.
Delivery Period	From first calendar day of delivery month until (and including) the last calendar day of the same month.

SOURCE: New York Mercantile Exchange (NYMEX).

price and the price of gas elsewhere in the United States (except Henry Hub, the delivery point). This differential, called the location basis, varies with time and thus poses a risk of its own. Consequently, the hedger must be careful to account for this risk when hedging.

- ***Cash flow risk:*** At the end of every day, the futures contracts are market-to-market, i.e., the futures prices on contracts are adjusted to reflect the closing price for the day. Daily gains and losses are calculated for all positions. The margin accounts, which are good faith deposits put down by futures participants with brokers, are then adjusted for these gains and losses. In the event of large losses an entity might find that it does not have sufficient cash flow to cover such losses (as required by NYMEX). This could be dangerous, especially for a hedger near bankruptcy.
- ***Credit risk:*** Since the futures position is used to hedge a forward position (or long-term contract), the hedger must ensure that the underlying contract is not breached. Such an event would leave the hedger with a naked futures position with potentially large losses. Flexible design and efficient pricing of long-term contracts can reduce the likelihood of contract breaches.
- ***Managerial risk:*** Hedging is a complex process and lack of understanding can lead to overhedged or underhedged positions. Furthermore, controls must be imposed on managers to ensure that they do not speculate when the objective of participation in the futures market is to hedge.

Even if gas industry participants do not take positions in futures, they can use the futures prices for reference in pricing long-term and spot contracts. Those taking positions in the futures market have substantial amounts of money at stake and thus attempt to gather as much information as possible on factors that would affect future gas prices. This information is factored into futures prices, which when used in conjunction with local spot prices can lead to efficient term contract pricing.

Options

Options are of two basic types: call options and put options. Options can be either on assets like stocks, grains, etc., or on other derivative instruments like futures (as in the case of crude oil and as proposed for natural gas).

- ***Call options:*** The holder of a call option has the right (but not an obligation) to buy the underlying asset (or futures) at a particular price (strike price) on a particular date in the future (exercise date). The buyer of the call option must pay an option premium to the seller. This premium is calculated using a standard formula called the Black-Scholes formula.
- ***Put options:*** A put option gives the owner the right (but not the obligation) to sell the underlying asset at the strike price on the exercise date.[3] As in the case of call options, the premium that the buyer must pay the seller can be easily calculated.

Natural gas options on futures have been proposed by NYMEX and are expected to be launched soon (Table 10-2 describes certain features of the NYMEX natural gas options on futures). Options can be used to hedge price risk like long-term contracts and futures; in addition, they allow the holders flexibility to take advantage of favorable price moves. Moreover, options can be bought at a number of different strike prices, whereas one can buy futures only at the prevailing market price.

- ***Example 4.1:*** In order to put a floor on the selling price of its gas in inventory, a producer can buy put options with a strike price at that limit. If the spot price of gas increases, the producer lets the option expire, sacrificing the premium but gaining on the higher gas sale price. If the price of gas declines below the spot price, the producer can exercise the put option and thus obtain a short position in natural gas futures contracts.

  The gain on exercising or liquidating this futures contract offsets the loss on the inventoried gas sale. Alternatively, the producer could sell the now-higher value put option and make a profit on the sale thereby reducing losses on the gas sale.

Option pricing theory can also be used to design long-term contracts with ceilings and

[3] These definitions are strictly true for European options, which can be exercised only on the exercise date. An American option can be exercised at any date prior to its maturity.

TABLE 10-2

PROPOSED FEATURES FOR NYMEX OPTIONS ON GAS FUTURES

Size of contract	One NYMEX natural gas futures contract
Minimum Price Fluctuation	$0.001/MMBTU (million British thermal units)
Trading Horizon	12 consecutive future months
Last Trading Day	Close of business on the third Friday of the month prior to the delivery month, provided that there are at least 3 days remaining to trade in underlying futures contract.
Strike Price	At least eleven strike prices are available anytime for calls and puts on underlying futures. The strike prices are in increments of $0.05/MMBTU
Exercise	No later than 6 p.m. or 45 minutes after the option price or the underlying futures price is posted, whichever is later, on any day prior to or on the day of option's maturity.

SOURCE: New York Mercantile Exchange (NYMEX)

floors in order to protect the buyer and seller from adverse price movements. These contracts can be priced using option pricing methods resulting in efficiently priced contracts that hedge supply and price risks.

Swaps

In a swap arrangement, one party agrees to pay the swap offer or a fixed price (or a price determined by formula) for the underlying asset. The swap price is periodically compared to a reference price and the parties then exchange payments depending on where the swap price is relative to the reference price.

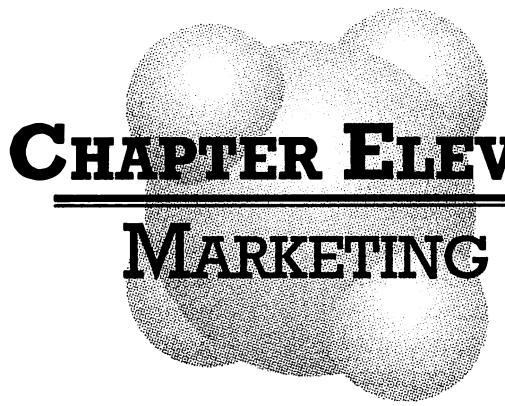
Natural gas swaps are offered by several financial institutions like Banque Paribas, Philbro, Chase Manhattan, etc., with terms ranging from 1 to 5 years.

- ***Example 5.1:*** An intermediary offers a swap purchase contract to an end user who wishes to establish a ceiling price to limit losses on ongoing gas purchases due to a rise in prices. The established reference price is the monthly average of the Henry Hub cash price. At the end of every month, the swap fixed price is compared to the reference price. If the reference price is below the swap price, then the end user pays the intermediary the per million BTU difference in prices on the entire volume covered by the swap. If the reference price is above the swap price, the intermediary pays the million BTU difference in prices to the end user.

Swaps can thus fix gas costs for an end user, making it easier for the end user to plan and obtain financing on projects; producers can also be guaranteed a fixed revenue stream with swap sale contracts. However, benefits from any swap must be evaluated against costs like transactions costs, potential losses from illiquid swap market conditions, evaluating the intermediary's credit rating, etc.

Conclusion

This discussion has provided an overview of the different financial tools that are available for price risk management in today's deregulated natural gas industry. The examples given above are illustrative and do not outline the only possible way to use these instruments. Different users will find different uses for the instruments or hybrids of the same depending on their individual risk profiles. While there are pitfalls, judicious use of these instruments can help gas industry participants better manage their gas portfolios.



CHAPTER ELEVEN
MARKETING

OVERVIEW

The natural gas industry is in a position to make a significantly greater contribution to the future energy needs of the nation. The gas industry has a strong and bountiful resource base that can meet the energy needs of its customers for many years to come, an extensive and expandable delivery system in place to supply natural gas when and where needed, and a product that is completely consistent with national policy.

Although faced with strong competition from other energy sources, the industry, if it chooses, can increase the market for natural gas by focusing on customers, determining their needs, and providing the products, services, and gas based technologies required to meet those needs. To achieve this, the upstream and downstream industry sectors will have to cooperate on a level not achieved in the past. A past history of fragmentation and fractiousness within the industry is recognized as a major barrier that needs to be replaced in order to effectively compete in a deregulated market and provide quality service to customers.

The transition to a free market at the producer and pipeline level has fostered healthy competition that provides customers with benefits at the burnertip that were not available in a fully regulated industry. To achieve the full potential that natural gas offers in meeting energy needs, the process of replacing regulation with competitive market forces needs to continue. State commissions should allow the transition to a free-market environment at the local distribution company (LDC) level wherever possible, while protecting those core customers who require full LDC service.

ISSUES AFFECTING THE INDUSTRY MARKETING POTENTIAL

To achieve its potential, the industry as a whole needs to recognize and resolve issues affecting its marketing capability in order to implement a proactive marketing approach that concentrates on the customer and stresses the value that natural gas provides in meeting their energy needs. Some of the specific issues that the industry needs to address are:

- The perception existing on the part of some customers and regulators that the industry does a poor job of marketing natural gas.
- The heavy focus of the industry on major growth potential markets such as power generation and gas cooling is important, but traditional markets such as residential/commercial space conditioning and industrial heat processing are not captive and are being targeted by electric competition as growth opportunities.
- The view that the industry is not providing an adequate level of support for the research, development, and commercialization of efficient new gas utilizing technology at the end-user level. Furthermore,

the industry itself is often seen as not committing to and adopting new gas technologies that could meet its needs and provide commercialization support in areas such as fleet vehicles, cooling, and engine-drive requirements.

- Fragmentation and past fractiousness within the industry have contributed to a concern on the part of some customers that the industry is not completely reliable. The information provided to customers concerning availability, deliverability, and price trends directly affects customers' deliberations on energy decisions, and also contributes to customers' perceptions of industry reliability.
- A dichotomy still exists between the industry's need to compete and grow, while being handicapped by existing regulations that can prevent the process.
- Buying natural gas can be very complicated. While the unbundling of services in the upstream sectors of the industry provides many benefits to customers, a higher level of understanding on the part of customers is required.

All of the issues identified that inhibit the marketing of natural gas can be overcome by a concentrated, cooperative effort by all segments of the industry. A synergistic industry concentrating on identifying and meeting customer needs will enable natural gas to reach its full potential in supplying the nation's energy needs.

MARKETING RECOMMENDATIONS

The industry already has taken major steps to improve its ability to market natural gas based on customer needs. Specific recommendations that the industry should implement in order to successfully market in today's competitive environment include:

- The industry needs to improve its overall marketing capability by adopting the philosophy that it will meet customer needs, as defined by the customer, and provide the resources and planning that will accomplish this.
- The industry needs to provide an adequate level of support for the development and commercialization of efficient new gas utilizing technology at the end-user level. This support is critical to the success of the industry in using new efficient gas equipment to develop new markets and remain competitive in existing markets.
- The industry must actively commit to and adopt new gas technologies when economical. It is a tremendous potential pilot resource for new gas technologies such as natural gas vehicles and gas cooling and this built-in market can offer manufacturers of newly developed gas equipment a strong commercialization resource.
- The industry needs to focus a major effort on demand growth, which will be a function of both the development of major market opportunities such as electric power generation, natural gas vehicles and gas cooling, and the identification and maximization of opportunities in niche markets such as gas engine drive, environmental emissions control, gas heat pumps, gas process cooling, and conversions.
- To increase demand at the LDC level, aggressive programs are needed to maintain existing market shares and to build new markets. Producers and pipelines need to support and leverage LDC efforts to compete in and increase markets by providing a full range of gas services designed to meet customer gas acquisition needs.
- Competition from other energy sources will be robust and will require the gas industry to focus on meeting customer needs in order to retain market share in existing markets, while developing new, non-traditional markets for natural gas.
- The gas industry jointly must educate customers about future availability and costs, the capability and reliability of the delivery system, and the development of new services and technologies that can satisfy customer needs.
- The industry and state regulators must find the correct way to allow the benefits of a free-market approach to accrue to the LDC level while at the same time protecting the core customers.

- The industry as a whole needs to make it as easy as possible to be a customer. The purchase and delivery of gas to the customer should be made simple and reliable within terms of the contract.

MARKETING CAPABILITY

A significant challenge facing the industry in the efforts to increase demand is its capability to market the product. The general perception, especially among large customers, is that the industry needs to be more effective in its marketing efforts—a view that was strongly reinforced by the focus group analysis.

The fact that the industry was heavily regulated until recently accounts in part for a generally conservative approach to the marketplace. Until the deregulation of the upstream segments of the industry began during the 1980s, normal risk/reward factors prevalent in other industries' marketing approach could not assume the role within the gas industry that they now are beginning to play. While offering the opportunity for the industry to change its approach to the marketplace, the deregulation process is also offering customers many more choices in meeting their energy needs than they had a few years ago. Customers can now begin to select and purchase the level of service they desire at the risk they are willing to assume. In a regulated industry, LDCs had the major responsibility for marketing the product. Deregulation in the producing and pipeline sectors of the industry has enabled them to market directly to the end users and this has required a transition on their part to a market driven approach. Deregulation also resulted in the creation of a new industry segment—the marketing company. The industry now is in the process of determining what marketing approaches best fit all of its segments in this increasingly non-regulated environment.

Another major perception that the industry must recognize and address in its approach to the marketplace is that of reliability. The regulatory-induced gas supply shortages of the 1970s remain very much in the minds of some customers as they make their energy decisions. Inconsistent information concerning availability, likely price trends, deliverability, and regulatory trends influence customer deliberations as they make energy decisions that will affect them and the gas industry for many years.

The industry needs to respond in a consistent manner to the reliability concerns on the part of customers as a key element of its marketing efforts. Determining customer needs and meeting them with agreements that provide competitively priced contracts consistent with the levels of service and security required by the customer is a necessary ingredient in the process. Customers must feel confident that they will receive, on a consistent and reliable basis, the level of service for which they contract. The ability of the gas industry to perform as agreed to and expected by the customers will go far toward reducing concerns about the reliability of service.

In addressing customers needs in today's marketplace, the gas industry cannot afford to function as order takers, but needs to take an aggressive approach. To be successful in competing in the market, it is essential to develop multi-level relationships with customers: learn what their decision-making process is, why they make the energy decisions they do, and become an integral part of that process.

Whether stated as being market driven, customer oriented, or customer responsive, all segments of the industry need to adopt a marketing philosophy that will meet the customer's needs as defined by the customer if natural gas is to achieve its potential in meeting the nation's energy requirements.

Throughout the industry, a number of producers, pipelines, and LDCs have developed effective and successful customer-oriented marketing approaches. The industry should identify and use these successful marketing approaches as a benchmark. These companies may differ in their approach to the marketplace in some aspects, but they do have many things in common that the industry as a whole needs to understand and adopt as initiatives in their approach to the marketplace. These factors include:

- Classifying customers based on their buying characteristics, in order to begin to understand their needs, designing specific plans to meet those needs, and developing continuing strategic partnerships with them. The traditional market segments of residential, commercial, industrial, and

power generation are far too broad to be addressed as entities in today's market. Within each are groups of customers whose needs and buying characteristics are unique, and these have to be identified and addressed.

- Developing and implementing functional business plans that define the markets, locate the opportunities and the problems, identify the resources required, and provide the road map to meet the opportunities.
- Developing trained and motivated marketing personnel by providing both technical and sales/marketing training to enable them to understand and meet the needs of the customer.
- Establishing an in-depth customer data base in order to develop and maintain customer information necessary to identify and meet their needs, define trends, identify market opportunities, and track competitive activities.
- Focusing on reducing costs and increasing benefits to customers by encouraging the adoption and use of high efficiency gas equipment at the end-user level.
- Implementing a comprehensive and continuing customer communication program consisting of approaches such as newsletters, seminars, and profile sheets to inform them of the benefits of gas, industry trends, and potential new uses that customers should consider.
- Establishing a sustained quality program in order to provide customers with the best service possible and to continue to change the industry approach to the marketplace from one that is regulatory driven to one that is customer driven.
- Using the end-user distribution channels at the LDC level such as equipment manufacturers, engineers and architects, and mechanical contractors to leverage marketing efforts and help build preference for the gas option in the customer's mind.

Within the gas industry itself, there exists a framework that has been used to address common problems. Umbrella organizations such as American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA), Natural Gas Supply Association (NGSA), and Independent Petroleum Association of America (IPAA), along with regional gas councils, have been used to fill this role. These resources could be used in innovative ways such as training, distributing informational materials, and coordinating target marketing support to help industry segments when the need arises.

All marketing segments of the industry will have to adopt a customer focused marketing effort and work together to implement it in order to increase the consumption of natural gas. Along with the earlier deregulation of the producer sector, the implementation of the FERC Series 636 Orders will complete the unbundling of the pipeline merchant function, and means that many gas end users who were not direct customers of the producer and pipeline community will assume that role in the future.

A final area that strongly affects the industry's marketing capability is its fragmented nature. Rather than working cooperatively together to meet the needs of the customer, the industry segments have, at times, put self-interest ahead of customer need with the result that customers sometimes view the gas industry as unresponsive. One result of the highly regulated past was that there were competitive arguments within the industry usually resulting in adversarial regulatory proceedings, and these situations made pursuing coordinated marketing efforts to grow new markets more difficult. The industry must continue to address this situation to ensure the development of cooperative relationships among industry segments, which will enable the gas industry to meet customer needs in the most effective way possible. The formation of the Natural Gas Council is an excellent first step. Another approach could be to have committee members in organizations such as AGA, INGAA, NGSA, and IPAA serve temporarily where possible in cross-functional roles in each others' organizations to facilitate the exchange of ideas and communication among the industry sectors.

MARKETING FOCUS

While all segments of the industry are involved in meeting customer needs on the gas supply side, the major responsibility for devel-

oping new markets and meeting competitive energy source threats at the end-user level lies primarily with the LDCs. Producers, pipelines, and marketing companies obviously have a vested interest in helping LDCs win new markets and meet the competition in existing markets. They also have a direct interest in and responsibility for many larger industrial facilities and power generation markets.

LDCs need to expand their systems wherever possible, adopt innovative new approaches to the market where allowed—such as equipment financing or cooperative advertising—encourage and champion the use of new efficient gas utilizing equipment, and aggressively pursue opportunities to market the gas option.

The industry has identified power generation, natural gas vehicles, and cooling as major market opportunities, and has developed an industry wide focus on developing these markets. Along with these major opportunities, there are strong potential niche markets such as cogeneration, direct engine drive, waste recycling and reuse, gas-based steel making, residential heating conversions, and lifestyle enhancements such as gas logs that could result in incremental gas consumption.

Whether dealing with the major potential market opportunities or the smaller niche markets, the industry needs to help attach added value to the product. Assisting customers by providing them with information on the efficient use of gas, educating them on newly emerging gas technologies, assisting them in securing air quality permits for gas equipment applications, and providing life-cycle cost information to support them in their decision-making process are examples of value added services that will truly help customers.

A logical approach for the industry to use to develop new market opportunities is to form industry teams to provide support for the demonstration of effective new technology, assist manufacturers in evaluating the results, develop a marketing plan on a national and regional basis, and work with the manufacturers to commercialize the product. Regulatory constraints on the recovery of these costs discourage this type of approach. The industry needs to work with state regulators on how the expenses of market development and technology commercialization are handled before LDCs commit significant funding to this type of process. At this time, regulation offers little incentive to expend resources on the commercialization and promotion necessary to help develop markets. This contrasts with the non-regulated markets, where business can reap the benefits of expenditures made to develop new markets.

While the major effort to expand gas consumption should appropriately be focused on the new large potential markets, the gas industry also needs to concentrate on its traditional core customer base. Residential and commercial space conditioning customers, as well as traditional industrial process steam and heat process customers, represent a very large share of today's market. In 1991, for example, consumption for these customers represented almost 80 percent of total throughput. These are not captive markets. Viable alternatives exist in all of these applications. While the customer is unlikely to switch to an alternative energy source in the short term, a substantial portion of this market could switch to an alternative fuel over a longer period of time. These markets, particularly the high value residential and commercial space conditioning and appliance areas, could be eroded over time if their needs are not addressed. Substantial continued effort must be made on the part of the gas industry to continue to maintain and expand the gas share in these markets.

DEMAND SIDE TECHNOLOGY

The introduction of new products will play a major role in the industry's effort to increase the use of natural gas. Demand-side technology will increase the efficiency of existing gas equipment, allowing the industry to remain competitive in existing markets, and provide the potential to gain new markets by developing and offering effective gas alternatives to competitive technologies.

The Gas Research Institute (GRI) is the major focal point of the gas industry's research, development, and demonstration (RD&D) efforts and the industry must satisfactorily resolve the GRI funding issue so that it can continue as a major gas industry asset. There is widespread recognition that the industry needs a strong research and development program. The consensus of the focus groups was that the

industry's research and development efforts are going in the right direction and have been reasonably successful, but should be increased in coverage and funding.

One possibility for increasing the size of the RD&D effort is to provide direct funding. The producing sector of the industry has been very active in providing supply-related RD&D funding in the form of private investment and has been allowed to realize the benefits of this investment. LDCs have been far less active in supplying direct funding for the development of end-use technologies because state regulation many times does not allow them the benefits accruing from the investment. State regulators could stimulate LDC participation in RD&D funding by allowing them to retain more of the benefits derived from successful RD&D activities.

Direct funding of end-user RD&D to complement the GRI activity would enable LDCs to speed the development of specific technology that has significant impact in their market area. This direct funding should be organized in conjunction with GRI's program to eliminate duplication of effort and to allow the benefits from the work to flow to other technology efforts in cases where synergies exist.

At the federal level, the industry needs to continue its efforts to ensure that natural gas research gets an equitable share of the DOE fossil fuel research dollars. While natural gas supplies about 24 percent of the energy consumed in the United States, funds allocated to natural gas research have varied between 2 and 6 percent of federal fossil fuel research funding over the last 13 years. Funding dedicated to coal has represented a large 85 to 90 percent of federal fossil fuel research funding. The increased recognition that the abundant natural gas resource base can support a much larger share of the nation's energy demand should result in a more balanced allocation of the federal government's fossil fuel research budget.

Another area of concern involves the adequacy of the gas industry's past and current efforts at commercializing new technologies. Questions exist regarding the industry's commitment to and support for the commercialization of new gas technologies. Currently, certain segments of the industry are involved in the commercialization process, but for the most part these efforts are modest and uncoordinated. Combined efforts within the industry to provide commercialization support in the form of commercialization centers are an appropriate start, but need to be expanded.

Most equipment manufacturers are fuel neutral and will supply whatever the markets want and what they feel can be profitable. The current overreliance of the industry on manufacturers of end-use equipment to establish the market has to be replaced with an industry plan to support them as partners in developing an industry-wide end-user technology commercialization plan. A number of industry organizations should be involved in the development of this plan, including GRI, AGA, and INGAA, among others. The gas industry has a vested interest in making sure that the market is asking for the gas option and that manufacturers see gas-fired equipment as a profitable option. A strong first step toward this end would be for the industry to increase and coordinate commercialization support by:

- Actively committing to and adopting new gas technologies when economical. The gas industry itself is a tremendous pilot resource for new technologies such as natural gas vehicles, gas cooling, fuel cells, and the emerging gas heat pump. This potential built-in market can offer manufacturers strong commercialization support.
- Addressing the issue that a number of promising gas technologies (e.g., gas heat pumps, gas space cooling) are slow in being accepted in the market because of higher initial costs than competitive equipment. The industry needs to find a way to help offset some of the first cost differential while new products go through the market entry phase. Because gas equipment can usually compete very effectively on life-cycle costs, the industry needs to focus on and communicate the benefits of gas equipment's lower life-cycle costs to a diverse audience, including: potential customers, lending institutions, equipment manufacturers, trade associations, the building industry, architects, and engineers.
- Developing funding approaches and supporting policies that will enable the GRI to play a more prominent role in the later

stages of the commercialization of new technologies in conjunction with gas industry groups and equipment manufacturers.

- Building on and expanding the activities of the existing gas industry commercialization centers and possibly combining them with an enhanced GRI commercialization role. An example is the Industrial Gas Technology Commercialization Center, established under the auspices of the AGA, which provides financial support to demonstrate and commercialize new technologies for industrial customers. The GRI currently plays an active role in the Center through the funding of specific demonstration projects. Similar centers have been established for the natural gas vehicle and cooling markets. Participation by additional industry players would increase the effectiveness of the centers and allow additional centers to be established to help commercialize technologies aimed at other markets such as residential/commercial space heating and water heating. The electric industry has done very well with this approach by establishing Electric Power Research Institute Technology Centers to support the development, testing, and commercialization of electro-technologies. The gas industry can learn from the competition.

THE COMPETITIVE ENVIRONMENT

The natural gas industry has the potential and capability to compete with alternative energy sources. The only thing that can prevent the gas industry from being competitive with other energy sources and expanding its role in meeting the nation's energy needs is the gas industry itself. Competition within the industry segments is healthy and will result in better service and more products that meet customer needs. While the constructive expression of ideas and points of view is a useful and beneficial process for planning the gas industry's future, unnecessary internal fragmentation and fractiousness make coordinated marketing efforts very difficult. Cooperative efforts across the industry segments need to be increased to meet the competition by creating and sustaining the services and reliability that meet customer needs.

The major external competition the industry faces is in the form of coal in the power generation area and in some industrial boilers, in the form of electric in many end-use applications, and in the form of oil usage in some residential/commercial heating markets, and industrial boilers. Oil in the form of reformulated gasoline will be the main competition in the evolving natural gas vehicle market along with the evolution of electric vehicles.

Coal has increased sales in the electric power generation market for all but 2 of the last 22 years. Coal currently has a 55 percent share of this market, up from 46 percent in 1970. In this same period, nuclear generation went from essentially zero to a 21 percent share. Much of these increases was due to decisions by traditional gas-consuming utilities to diversify their fuel mix and the enactment of the Powerplant and Fuel Use Act. Both were prompted, to a degree, by the long-term gas supply concerns in the 1970s. Since the mid 1970s, the natural gas share of the power generation market has declined from 24 to 9.4 percent. Coal's success can be attributed to several reasons:

- Large known reserves
- Low price compared to natural gas
- Visible, tangible, and can be stored at the point of use
- Substantial governmental support in the form of R&D funds to develop clean coal technology.

The coal industry also structured itself to survive and make a profit in very lean times. Gas producers have developed this approach as well and the industry must continue to do so in all segments.

Based on electric industry projections of new capacity to be built in the 1990s, natural gas has the opportunity to do very well. The industry, however, should not take anything for granted. The gas industry needs to push its major advantages in the competition against coal. The overwhelming environmental benefits, the ease and flexibility of use, the size of the resource base, and the lower capital cost requirements compared to coal add considerable value to the product and can be used to off-set the market price differential between gas and coal. The gas industry can also lay the groundwork for mutual cooperation with

the coal industry in areas such as seasonal co-firing and reburn where natural gas can help coal-fired facilities meet emission requirements.

Strong competition from the electric industry in traditional gas markets will be a major challenge for the industry in coming years. The electric industry, as a whole, has done very well in positioning electric equipment as modern, efficient, and highly productive. The structure of the electric industry is such that the production, transmission, and distribution of electric power are more of an integrated operation than the discrete segments of the gas industry. This has allowed the electric industry to speak more effectively to the customer in one voice and makes it easier to develop regional and national strategies to promote the use of electric equipment and to target market.

Another factor that will influence gas and electric end-use competition is the expanding role of Integrated Resource Planning (IRP). While a wide variety of energy efficiency and Demand Side Management (DSM) type programs have been underway in the gas industry for many years, implementation of IRP is expected to increase this trend. Since IRP requires utilities to investigate both supply side options, as well as demand related programs in determining the most cost-effective investment options to deliver energy services to customers, IRPs will provide opportunities for both gas and electric utilities to compete. It is essential that the gas industry work closely with regulators to ensure that IRPs provide equal opportunity in the marketplace for gas equipment. The gas industry should plan now for the fact that state regulators will extend the DSM/IRP process to the gas industry at the LDC level. Properly designed IRP programs could be a major factor in speeding the acceptance of efficient gas equipment by the marketplace.

Oil competition is primarily regional in nature in the residential and commercial market sectors. In the East and Northeast, there still is major competition between oil and gas, with gas being the preferred customer option where available and competitively priced. Suppliers of oil to the commercial and residential markets are defending their remaining customer base by raising safety concerns regarding natural gas. The gas industry needs to defend against scare tactics by educating customers on the excellent safety record associated with the use of gas and making them aware of the increasing availability of gas as new pipelines and distribution systems expansions are completed.

In the industrial market, oil usage is primarily confined to specialized uses where the inherent characteristics of the energy form is the major criteria, such as feedstocks or by-products of refining operations that are consumed in the process, and to larger boiler operations where natural gas is either not available or where oil has a significant price advantage.

There is small remaining potential to switch industrial oil consumption to gas since most industrial customers have already selected the gas option. There is, however, a major potential for industrial customers to switch from gas to oil because there is much fuel switching capability in place. If gas prices rise without a comparable increase in oil prices, these industrial users would have a major incentive to switch from gas to oil.

POWER GENERATION

Power generation represents the greatest single market opportunity for the natural gas industry with a potential to supply an additional 2 to 4 trillion cubic feet to this market. After a decline in natural gas consumption during the 1970s and early 1980s, due to regulatory induced shortages, rapidly increasing prices, legislative initiatives such as the Powerplant and Industrial Fuel Use Act, and pessimistic supply estimates, the gas industry is seeing a renewed interest and opportunity to significantly increase the consumption of gas for power generation. Natural gas offers a number of advantages to the electric industry:

- A large resource base.
- Low capital costs compared to other electric options.
- Superior environmental characteristics.
- Gas generating plants require shorter lead time and can be built in modules.
- High operating efficiencies resulting from improvements in turbine and combined cycles technology.

Natural gas is positioned to be the solution to meet future generating demand growth by utilities and independent power producers. The high efficiencies offered by new gas-fired turbines and combined-cycle facilities, lower capital and non-fuel operating costs, modularity, and shorter construction time make natural gas a highly attractive solution to power generation needs. In order to meet the promise that this market presents, the gas industry must work closely with the electric industry to resolve their concerns about price, deliverability, and reliability.

The gas industry has developed a proven track record in meeting the needs of the historical electric generation market in the South, West, and New York. This same reliability has to be made available to power generators in the Midwest and the rest of the Northeast, where major opportunities exist to expand the market, and where there is far less experience in the use of natural gas as an energy source for power generation. The gas industry will have to invest in pipeline and storage expansions to serve these loads and will need to meet the pipeline pressure and instantaneous peak requirements that these large loads require. These issues are engineering problems and can be resolved. The key criteria to the increased consumption of gas is the gas industry's ability and commitment to deliver gas at a competitive price when and where it is needed.

Contractual arrangements will have to be flexible to meet the needs of utilities and independent power producers. The gas industry should continue to develop and refine specific product offerings for the electric industry such as storage and seasonal pricing to accommodate the unique requirements of the electric industry.

The natural gas and electric power generation industries must continue to develop and expand inter-industry communication, understanding, and mutual problem solving through comparable industry groups.

THE EFFECT OF REGULATION ON THE MARKETING ENVIRONMENT

The deregulation process in the producing and pipeline sectors of the industry has enabled the industry to begin to rely on market forces to define customer needs and to shape the products and services to meet these needs. Although a good deal of uncertainty remains, the industry is certainly headed in the right direction to take better advantage of the resource base and the delivery system.

At the LDC level, regulators need to encourage the shift to a competitive market wherever possible, while ensuring that core customers, who do not have the choices available to them that a deregulated industry offers, are provided reliable service at a reasonable cost. Although LDCs will continue to be regulated by state commissions, this should not be used as an excuse for not taking a customer responsive approach to the market. To do so would be an inscribed invitation to their also regulated electric competitors to take over the end-user market.

State commissions are struggling to respond to changes in federal regulation, such as the FERC Series 636 Orders, that have resulted in a growth of healthy competition within the gas industry. These changes are already affecting the services offered to and by LDCs and the risks and responsibilities being imposed on them. Where it is to the customer's benefit, the state commissions should allow LDCs to function as fully as possible in this new competitive environment. Regulatory policy that continues to treat natural gas as a scarce commodity and favors existing customer groups over the development of new opportunities is short sighted in view of an available resource base that can meet existing customer demand and new market opportunities while spreading costs over an increasing market base to the benefit of all customers.

Regulators need to remove cross-subsidies of one class of customers by another. By artificially creating low prices for some classes of service and high prices for others, the market is being distorted and incorrect price signals are affecting the decisions of buyers and sellers of service.

As stated above, the industry should prepare for the adoption by state regulators of Integrated Resource Planning and Demand Side Management for the gas industry. These programs are well established in the electric industry. IRP and DSM will require an LDC to function both as an energy manager for itself

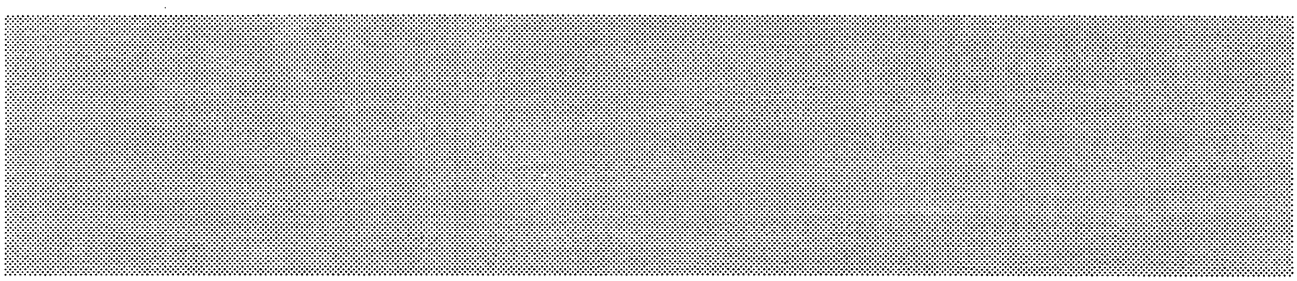
and for its customers, and will call for an extensive marketing resource reallocation on the part of LDCs.

Another regulatory initiative that will significantly affect LDCs, and consequently the other segments of the industry, is the first phase of the National Appliance Energy Conservation Act, effective January 1992. The Act mandates higher efficiency standards for appliances manufactured after that date. Normal replacement of existing residential equipment and those installed in new construction will result in the continued decline in average consumption per customer. The challenge will be to offset this decline by increased market share in the new construction markets and the pursuit of incremental loads such as gas logs, gas lights, and grills, which can offset losses due to the adoption of more efficient equipment. RD&D resulting in high efficiency gas equipment will be essential to enable the gas industry to continue to dominate and expand these markets.

A unique regulatory issue facing LDCs that also impacts the rest of the industry are municipal building codes. These codes vary significantly from area to area, and make it difficult for the gas industry to attain timely approval and acceptance of innovative technology that improves efficiency and speeds installation. An example is the use of flexible piping. The industry should encourage a more uniform approach to technology innovations on the part of municipalities to ensure their effective introduction to the marketplace.

CONCLUSIONS

The potential of natural gas to meet an increased share of the nation's energy needs is readily apparent and the barriers to achieve this potential are within the ability of the industry to manage. The gas industry can choose a marketing approach encouraging healthy competition among segments and an overall cooperative approach to meeting customer needs that will result in a growing market that recognizes natural gas as the future energy of choice. The combination of an aggressive customer-focused marketing approach with strong support for new gas technologies designed to meet customer needs is the best way for the gas industry to maximize that growth.



CHAPTER TWELVE
LEADERSHIP

OVERVIEW

This study has developed four recommendations for improvements in the area of leadership. First and foremost, the industry needs to develop a consistent and coherent vision of where it is going. Second, the industry needs to educate both itself and its customers on the facts about natural gas. Third, the industry needs to communicate and coordinate with its customers in order to best satisfy their objectives. Fourth, the industry needs to encourage and support its own internal natural gas use, especially in the areas of vehicles and cooling.

WHY LEADERSHIP IS AN ISSUE

Until recently, the U.S. natural gas industry could best be characterized as one in which the primary industry players had adversarial relationships with one another. The thrust of each participant's efforts has historically been to fight over a static pie rather than expanding the overall size of the pie. Dramatic changes in the industry due to deregulation, commodity price fluctuations, and overall economic conditions have further illuminated the problems with these relationships. Recent efforts by industry participants to work together for the common good of increasing gas demand, such as the formation of the Natural Gas Council, give promise that the industry has acknowledged its troubled relationships and is working with a more unified approach toward industry improvement. However, further improvements in the leadership area are necessary as the industry moves forward.

Over time, the natural gas industry has exhibited many of the characteristics of an industry without strong leadership. There have been well known historical reasons for this. Perhaps the most significant reason is the lack of integration of the various industry segments. There are very few integrated gas companies that own production, transmission, and distribution facilities. An industry as fragmented as the natural gas industry is structured to work separately.

The regulatory framework has also been a very significant contributor to the lack of strong leadership in the natural gas industry. As long as transmission and distribution rates are regulated, there is a significant incentive for each party facing higher rates to reduce its share of the cost and increase the cost paid by others. This has created a number of conflicts among and between industry segments. For transmission companies, it has created an environment where producers have been competing against pipelines for merchant sales business. Also for transmission companies, it has created a rate case environment where distributors are attempting to reduce their share of cost and to increase other distributors' share of cost. In the distribution sector, it has resulted in the development of industrial user

groups and consumer groups attempting to minimize their share of cost paid by either industrial or residential users. Discussions of the prospect of significant price rises and future shortages has also impacted potential use of natural gas. In recent times, the difficulty of funding the Gas Research Institute has provided a vivid example of the frustrations of an industry that understands the importance of technology, yet has difficulty finding the funds to finance the research and development activity.

Summary of Focus Group Results

The focus group participants confirmed many of the problems faced by the natural gas industry. The focus group summary has identified a deep-seated mistrust and dislike for segments of the natural gas industry among some publics. The study also identified mistrust by some consumers toward regulation and management of regulated companies. Fractiousness was identified by focus group participants as the most significant problem facing the industry. The tendency of the gas industry's segments to fight with one another was cited by all focus groups as one of the industry's least useful characteristics.

While improving its credibility is one of the major challenges facing the industry, the other challenges highlighted by the focus groups indicate an industry that could benefit from improved leadership; these include the challenge to improve marketing and become customer driven, the challenge to improve reliability, and the challenge to reduce the impact of regulation.

Traits of an Energy Industry Leader

It is important to identify some possible traits that would define the natural gas industry as one with strong leadership. The first of these traits is providing a quality product as well as packaging that product with quality services that meet customer needs and expectations. A leading industry would be highly competitive and would have an influence in the overall growth of the market. Industry participants would find innovative methods for product extraction, transportation, and storage, as well as end use. The industry players would have healthy financial profiles and would use the regulatory process to better serve their customers. And finally, the industry would be a leader when it is perceived as trustworthy and reliable.

Recent Efforts to Improve Leadership of the Natural Gas Industry

There has been a substantial increase in the natural gas industry's propensity to work together over the past few years. There have been many signs of this including the formation of the Natural Gas Council with participants from each industry segment and each major natural gas trade association. Overall, there has not been a time where producers were more interested in developing relationships with end users and distributors or where end users and distributors were more interested in developing relationships with producers. This is in part attributable to the move toward a competitive market initiated by the Federal Energy Regulatory Commission as well as an increase in industry awareness of the benefits of presenting itself as a unified industry to potential customers. The progress that has been made to date in the area of leadership is significant, but there is additional progress required. The following recommendations have been developed in this area of leadership to achieve that progress.

RECOMMENDATIONS

Create a Vision for the Natural Gas Industry

An obvious first step in developing strong leadership for the natural gas industry is to create a consensus view on where the industry would like to be in the future. To this end, several organizations including the Department of Energy, the Interstate Oil and Gas Compact Commission, and the Natural Gas Council have developed visions of where the natural gas industry should be headed in the future. These visions are remarkably consistent and if the industry can rally around these visions, it would be a major first step in achieving the appropriate role of natural gas in the U.S. energy mix.

Educate

There is a need for the industry to educate itself as well as consumers and federal,

state, and local regulators about the benefits of natural gas.

- Actively publicize information about: (1) new estimates of the North American resource base; (2) improved technology to find and produce gas at lower cost than in the past; and (3) the absence of the need to maintain a reserve-to-production ratio above current levels.

  Supply, more than any other factor, has been identified as a constraint historically on the growth of natural gas. As a result of the industry's efforts in the past, supply can be made available on an economic basis to meet the demands of the natural gas industry and as such supply should not be viewed as a constraint. The in-depth analysis of the Source and Supply Task Group (Volume II) supports this statement. An active program to educate both the industry and the public about supply needs to take place.

- Perform and publicize an objective analysis of the facts about life-cycle and other costs and environmental advantages of gas cooling and other applications.

- Educate the industry about the need for an improved customer and service orientation. Too often customers are not considered in the decisions by industry. Efforts should be undertaken by the natural gas industry to take the customer view.

Communicate

There is a need for better communication with potential customers in the industry. To that end, the following action items are recommended for implementation by the industry.

- Improve communication and coordination between the natural gas and electric generation industries. There have been several significant efforts in this area, including this NPC study itself as well as the Interstate Natural Gas Association's Power Generation Task Force. This communication is an ongoing process that deserves the support of trade associations and individual companies.

- The industry needs to encourage federal and state policies and guidelines that explicitly recognize the potential of natural gas to enhance national economic growth and achieve national environmental goals. While the industry has made significant progress in this area, an industry with strong leadership can be expected to continue this effort. As part of this effort, the gas industry can benefit from a better understanding of the issue of externalities and how the environmental characteristics of natural gas can be incorporated into the fuel choices of energy consumers.

- The industry needs to communicate its willingness to install the facilities necessary to provide desired services on an economic basis. Not all end users are aware that natural gas facilities can be added on an economic basis to serve their needs. The industry needs to make potential customers aware and support a process that can put those facilities in place on a timely basis.

- Communicate views among the various segments of the gas industry, end users, regulators, and other governmental officials with environmental, energy conservation, and consumer advocacy groups so as to support potential gas markets. The trade associations can be instrumental in implementing this recommendation.

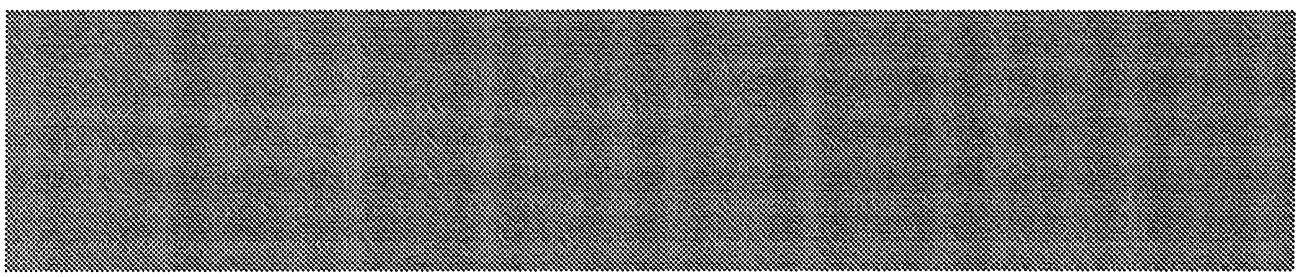
- Establish an identity of its own for natural gas as a clean fuel and as a sound business distinct from oil, as well as use market forces rather than regulation to achieve industry growth.

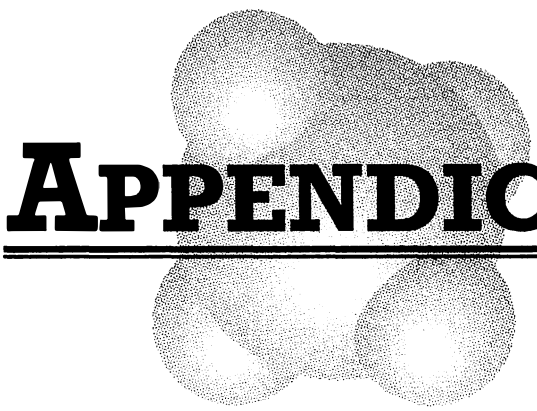
Act

The NPC believes that individual companies and organizations involved in the natural gas industry can help lead the industry by taking an active role in developing applications for natural gas for their own use. This could be, as an example, purchase of natural gas vehicles for use in their own fleets. Another example would be the purchase of gas-fired cooling equipment to put in their own facilities. The industry can take many actions itself to use natural gas and thereby encourage potential customers of natural gas to make the decision to use natural gas in their facilities.

OVERALL IMPACT OF RECOMMENDATIONS

Implementation of the leadership recommendations is critical to achieving the optimal future of natural gas in the United States. While it is difficult to quantify the impact, without an increased effort by the industry to work together, natural gas will be fortunate to maintain its existing market share and could face continued erosion in market share over time. Conversely, with proper leadership, the natural gas industry can achieve its optimal role in serving the energy and environmental needs of the United States.





APPENDICES

Appendix A

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:

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,

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.

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Mark W. Nordheim
Coordinator, Air Quality Issues
Health, Environment and Loss Prevention
Chevron Corporation

SOURCE AND SUPPLY TASK GROUP

A. C. Overpeck III
Director, Planning and Development Group
Gas Department
Texaco U.S.A.

Mark G. Papa
Senior Vice President, Operations
Enron Oil and Gas Company

Allan B. Quiat
Manager, Gas Supply
Chevron U.S.A. Inc.

S. Scott Sewell
Director
Minerals Management Service
U.S. Department of the Interior

R. E. Sidle
Manager, Business Analysis
Shell Oil Company

William Trapmann
Senior Industry Economist
Office of Oil and Gas
Energy Information Administration
U.S. Department of Energy

L. O. Ward
Owner-President
Ward Petroleum Corporation

James W. Williams
Planning Consultant
ARCO Exploration and
Production Technology

John H. Wood
Director
Dallas Field Office
Energy Information Administration
U.S. Department of Energy

SPECIAL ASSISTANTS

Robert L. Brown
Senior Technical Advisor
Exxon Company, U.S.A.

Joseph B. Corns
Director
Industry Analysis and
Forecasts, North America
Amoco Corporation

Brad G. Defenbaugh
Senior Planning Advisor
Mobil Natural Gas Inc.

Toni D. Hennike
Senior Counsel
Hunt Oil Company

Hugh E. Hilliard
Deputy Associate Director
Policy, Planning & Appeals
Minerals Management Service
U.S. Department of the Interior

Bill L. McFarland
Manager
Natural Gas Regulatory Affairs and
Business Development
Unocal Corporation

Albert L. Modiano
Deputy Director
Minerals Management Service
U.S. Department of the Interior

Deborah L. Plattsmier
Manager
LNG Business Development
Gas Department
Texaco U.S.A.

John J. Pyrdol
Fossil Fuel Supply Analyst
Office of Planning and Environment
Office of Fossil Energy
U.S. Department of Energy

Thomas J. Woods
Principal Energy Analyst
Gas Research Institute

CONVENTIONAL SUBGROUP

GROUP LEADER

Terry L. Day
Manager
Upstream Planning and Analysis
Exxon Company, U.S.A.

* * *

Thomas S. Ahlbrandt
Chief
Branch of Petroleum Geology
U.S. Geological Survey

Joe H. Broome
Professional Petroleum Engineer
Texaco Inc.

Robert L. Brown
Senior Technical Advisor
Exxon Company, U.S.A.

David B. Crawford
Senior Staff Production Engineer
Chevron U.S.A. Inc.

Robert J. Finley
Associate Director
Bureau of Economic Geology
University of Texas at Austin

Donald L. Gautier
Chief
Branch of Petroleum Geology
U.S. Geological Survey

Michael I. German
Senior Vice President
Planning and Analysis
American Gas Association

Gary T. Holley
Vice President
U.S. Operations
Parker Drilling Company

John C. Houghton
Planning Consultant
ARCO Exploration and Production Technology

Paul V. Hyde
Director
Reservoir Engineering
Columbia Natural Resources, Inc.

Paul E. Martin
Chief
Resource Evaluation Division
Minerals Management Service
U.S. Department of the Interior

Fred W. Nagle
Energy Resource Consultant
Mobil Oil Corporation

John J. Pyrdol
Fossil Fuel Supply Analyst
Office of Planning and Environment
Office of Fossil Energy
U.S. Department of Energy

A. T. Smith
Section Supervisor
Chevron Oilfield Research Company

William Trapmann
Senior Industry Economist
Office of Oil and Gas
Energy Information Administration
U.S. Department of Energy

Robert G. Vollmert
Deputy Director
Office of Business Operations
Office of Fossil Fuel Energy
U.S. Department of Energy

Stanley L. Walker
Coordinator - Production
Exploration Land and Production
Chevron U.S.A. Inc.

John H. Wood
Director
Dallas Field Office
Energy Information Administration
U.S. Department of Energy

Thomas J. Woods
Principal Energy Analyst
Gas Research Institute

CONVENTIONAL SUBGROUP (Continued)

SPECIAL ASSISTANTS

Richard F. Mast
Geologist
Branch of Resource Analysis
U.S. Geological Survey

Albert L. Modiano
Deputy Director
Minerals Management Service
U.S. Department of the Interior

NONCONVENTIONAL SUBGROUP

GROUP LEADER

Edward L. Flom
Manager
Industry Analysis and Forecasts
Amoco Corporation

GROUP CO-LEADER

Daniel A. Dreyfus
Vice President
Strategic Planning and Analysis
Gas Research Institute

* * *

Thomas S. Ahlbrandt
Chief
Branch of Petroleum Geology
U.S. Geological Survey

Kenneth E. Baum
Director
Drilling Technology
ARCO Oil and Gas Company

Thomas J. Bergstresser
Petroleum Geologist
Frontier Division
Western Exploration Business Unit
Chevron U.S.A. Inc.

Robert L. Brown
Senior Technical Advisor
Exxon Company, U.S.A.

Robert L. Brown
Manager
Gas Marketing Development
Mobil Oil Corporation

Charles W. Byrer
Project Manager
Coalbed Methane
U.S. Department of Energy

Joseph B. Corns
Director
Industry Analysis and
Forecasts, North America
Amoco Corporation

David B. Crawford
Senior Staff Production Engineer
Chevron U.S.A. Inc.

Stephen E. Eads
Vice President
Planning and Marketing
Columbia Natural Resources, Inc.

Ian A. Fischer
Producing Manager
Rocky Mountain Area
Mobil Exploration and Producing U.S. Inc.

Cynthia W. French
Petroleum Geologist
Chevron U.S.A Inc.

Michael M. Helland
Staff Director
Industry Supply Analysis
Amoco Corporation

H. William Hochheiser
Physical Scientist
Office of Geoscience Research
Office of Fossil Energy
U.S. Department of Energy

Courtney F. Isselhardt
Senior Exploration Geologist
Western Exploration and Production Division
Texaco U.S.A.

Mark G. Papa
Senior Vice President, Operations
Enron Oil and Gas

Raymond J. Pashuck
Geological Consultant
Rocky Mountain Area
Mobil Exploration & Producing U.S. Inc.

Kent F. Perry
Assistant Director
Tight Sands & Gas Processing Research
Gas Research Institute

Dudley D. Rice
Geologist
Branch of Petroleum Geology
U.S. Geological Survey

John H. Wood
Director
Dallas Field Office
Energy Information Administration
U.S. Department of Energy

Thomas J. Woods
Principal Energy Analyst
Gas Research Institute

SPECIAL ASSISTANTS

Mian M. Ahmad
Manager, Reservoir Engineering
Columbia Natural Gas Resources, Inc.

Brad G. Defenbaugh
Senior Planning Advisor
Mobil Natural Gas Inc.

Richard F. Mast
Geologist
Branch of Resource Analysis
U.S. Geological Survey

Brendan E. Quirin
Senior Economist
Amoco Corporation

Michael A. Roberts, Jr.
Corporate Planning Consultant
Enron Corp.

Charles W. Spencer
Geologist
Branch of Petroleum Geology
U.S. Geological Survey

IMPORTS AND ALASKA SUBGROUP

GROUP LEADER

A. C. Overpeck III
Director, Planning and Development Group
Gas Department
Texaco U.S.A.

GROUP CO-LEADER

Robert B. Kalisch
Director - Gas Supply and Statistics
American Gas Association

* * *

Howard Ash
Natural Gas Specialist
Infrastructure, Energy and
Environmental Division
The World Bank

Greg Broschka
Market Development
Amoco Canada Petroleum Company Ltd.

Reginald Cameron
Economist, Business Environment
Natural Gas Marketing
Petro-Canada Resources

Wilson W. Crook, III
Planning Specialist
Mobil Natural Gas Inc.

John W. Glynn
Director - Policy Analysis Division
Office of Fuels Programs
Office of Fossil Energy
U.S. Department of Energy

Victor W. Hughes
Manager, Natural Gas Issues
BP Exploration

IMPORTS AND ALASKA SUBGROUP (Continued)

Joseph W. Lagler
Metairie Site Office
U.S. Department of Energy

Deborah L. Plattsmier
Manager
LNG Business Development
Texaco U.S.A.

Donny R. Scott*
Senior Energy Analyst
Corporate Planning and Analysis Department
Chevron Corporation

R. E. Sidle
Manager, Business Analysis
Shell Oil Company

Walter J. Talley
Consultant, Corporate Budgets
Planning and Economics
Unocal Corporation

L. Carl Thompson
Manager - Supply and Transportation
Pan National Gas Sales, Inc.

William Trapmann
Senior Industry Economist
Office of Oil and Gas
Energy Information Administration
U.S. Department of Energy

Royal Watts
Petroleum Engineer
Morgantown Energy Technical Center
U.S. Department of Energy

W. T. Zittlau
Business Planning Analyst
Amoco Canada Petroleum Company Ltd.

*Deceased (January 3, 1993)

TECHNOLOGY SUBGROUP

GROUP LEADER

James W. Williams
Planning Consultant
ARCO Exploration and
Production Technology

* * *

Charles F. Brandenburg
Director, Enhanced Recovery
Coal Seams and Shales
Gas Research Institute

Robert L. Brown
Manager
Gas Marketing Development
Mobil Oil Corporation

Thomas S. Buxton
Director
Reservoir Engineering Section
Amoco Research Center

Joseph B. Corns
Director
Industry Analysis and
Forecasts, North America
Amoco Corporation

John M. Dees
Senior Well Completion Engineer
Oryx Energy Company

Daniel A. Dreyfus
Vice President
Strategic Planning and Analysis
Gas Research Institute

Alan S. Emanuel
Section Supervisor
Chevron Oilfield Research Company

Robert J. Finley
Associate Director
Bureau of Economic Geology
University of Texas at Austin

Edward L. Flom
Manager - Industry Analysis and Forecasts
Amoco Corporation

K. H. Frohne
Petroleum Engineer/Project Manager
U.S. Department of Energy

Michael I. German
Senior Vice President
Planning and Analysis
American Gas Association

Robert B. Kalisch
Director
Gas Supply and Statistics
American Gas Association

Christopher B. McGill
Manager
Gas Supply Programs
American Gas Association

J. Michael Melancon
Chief, Reserve Section
Mineral Management Service
U.S. Department of the Interior

A. C. Overpeck III
Director, Planning and Development Group
Gas Department
Texaco U.S.A.

Allan B. Quiat
Manager, Gas Supply
Chevron U.S.A. Inc.

Frank W. Robl
Associate Reservoir Engineering Consultant
Mobil Exploration and
Producing Services, Inc.

Irwin R. Supernaw
Senior Scientist
E&P Technology Department
Texaco Inc.

Leon L. Tucker
Director
Energy Modeling Services
American Gas Association

James D. Twyman
Manager
Borehole Technologies
Atlantic Richfield Company

Thomas J. Woods
Principal Energy Analyst
Gas Research Institute

ENVIRONMENTAL REGULATIONS SUBGROUP

GROUP LEADER

Mark W. Nordheim
Coordinator, Air Quality Issues
Health, Environment and Loss Prevention
Chevron Corporation

* * *

Raymond L. Banks
Environmental Specialist
Amoco Corporation

Glynn T. Breaux
Senior Environmental &
Regulatory Engineering Advisor
Mobil Exploration and Producing, U.S.

Randolph C. Bruton, Jr.
Vice President
Regulatory Affairs
Mitchell Energy Corporation

Michael J. Faust
Senior Exploration Geophysicist
Upstream Planning & Analysis
Exxon Company, U.S.A.

ENVIRONMENTAL REGULATIONS SUBGROUP (Continued)

Orval L. Fouse
Senior Environmental Specialist
Health, Environment and
Loss Prevention
Chevron Corporation

Nancy L. Johnson
Physical Scientist
Office of Planning and Environment
Office of Fossil Energy
U.S. Department of Energy

R. E. Sidle
Manager
Business Analysis
Shell Oil Company

Jeffrey P. Zippin
Chief
Branch of Environmental Operations
and Analysis
Minerals Management Service
U.S. Department of the Interior

CONTRACT DIVERSITY SUBGROUP

GROUP LEADER

Bill L. McFarland
Manager
Natural Gas Regulatory Affairs and
Business Development
Unocal Corporation

* * *

E. Russell Braziel
Vice President - Marketing
Texaco Gas Marketing Inc.

Toni D. Hennike
Senior Attorney
Hunt Oil Company

Victor W. Hughes
Manager, Natural Gas Issues
BP Exploration

Allan B. Quiat
Manager, Gas Supply
Chevron U.S.A. Inc.

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Public Service Electric & Gas Company

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Senior Vice President
Planning and Analysis
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Paul D. Holtberg
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Gas Research Institute

Joseph T. Hydok *(Region 2)*
Executive Vice President Gas Operations
Consolidated Edison Company
of New York, Inc.

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Senior Vice President
U.S. Generating Company

Richard L. Itteilag *(Region 7)*
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Residential/Commercial Marketing and Sales
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Senior Vice President
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Executive Vice President
Columbia Gas Distribution Companies

Charles W. Linderman
Director
Fossil Fuels and Renewable Programs
Edison Electric Institute

James V. Mahoney
President
New England Energy Incorporated
New England Electric System

* Regional analysis leader. See page B-15 for description of regions.

DEMAND AND DISTRIBUTION TASK GROUP

A. E. Middents *(Region 8)*
Senior Vice President
Gas Operations
Public Service Company of Colorado

Donald W. Niemiec
President
Union Pacific Fuels Inc.

R. E. Oerman *(Region 6)*
Manager, Natural Gas
Planning & Economics
Shell Oil Company

Charles L. Pyle
Acting Planning Manager
Mobil Natural Gas Inc.

David E. Rosenberg *(Region 4)*
Specialist, Gas Economics
Enron Corp.

Glenn R. Schleede
President
Energy Market & Policy Analysis, Inc.

J. Edward Smith
Director
Market Planning & Analysis
Washington Gas Light Company

John F. Stefani *(Region 10)*
Vice President
Gas Supply & Industrial Marketing
Washington Natural Gas Company

Thomas W. Wagar
Director
Industrial Marketing
The East Ohio Gas Company

Roger A. Young *(Region 1)*
President and Chief Executive Officer
Bay State Gas Company

SPECIAL ASSISTANTS

Terry W. Day
Energy Advisor
Downstream Planning & Analysis
Exxon Company, U.S.A.

Daniel A. Dreyfus
Vice President
Strategic Planning and Analysis
Gas Research Institute

Marita A. Fegley
Senior Marketing Analyst
Market Planning & Analysis
Washington Gas Light Company

Michael S. Flaherty
Economic and Policy Analyst
The New England Gas Association

Fred B. Gerber
Consultant
Business Development
ARCO Oil and Gas Company

Kurtis J. Haeger
System Planning and Forecasting Manager
Gas Planning
Public Service Company of Colorado

Thomas M. Kiley
President
The New England Gas Association

Walter V. Kolu
Manager, Gas Planning
Public Service Electric & Gas Company

Andy S. Kydes
Senior Modeling Analyst
Office of Integrated Analysis and Forecasting
Energy Information Administration
U.S. Department of Energy

Richard D. Langley
Director, Demand Forecasting
Columbia Gas Distribution Companies

Lad P. Lorenz
Manager, Supply Operations
Southern California Gas Company

Frederick J. Nemergut
Vice President
Reed Consulting Group

G. Hayden Sherrill
Manager, Business Development
Union Pacific Fuels Inc.

James M. Todaro
Senior Analyst
Reserves and Natural Gas Division
Energy Information Administration
U.S. Department of Energy

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Region	States
1	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont
2	New Jersey and New York
3	Delaware, Maryland, Pennsylvania, Virginia, Washington, D.C., and West Virginia
4	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee
5	Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin
6	Arkansas, Louisiana, New Mexico, Oklahoma, and Texas
7	Iowa, Kansas, Missouri, and Nebraska
8	Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming
9	Arizona, California, and Nevada
10	Idaho, Oregon, and Washington

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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

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

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Chairman and
Chief Executive Officer
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Acting Deputy Assistant Secretary
Fuels Programs
Office of Fossil Energy
U.S. Department of Energy

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Vice President,
Physical Risk Management
Enron Gas Services Group

SECRETARY

Marshall W. Nichols
Executive Director
National Petroleum Council

* * *

Charles W. Bass
Senior Vice President
Governmental and Regulatory Affairs
Atlanta Gas Light Company

Karen A. Berndt
Director
Gas Department
Texaco Exploration and Production Inc.

Denise A. Bode
President
Independent Petroleum Association
of America

Douglas R. Bohi
Director
Energy and Natural Resources Division
Resources for the Future

Nancy S. Boyd
Board Member
Iowa Utilities Board

Scott L. Campbell
Partner
Washington Policy and Analysis

Salvatore J. Casamassima
General Counsel
Exxon Production Research Company

James M. Coyne
Manager
Strategic Planning
Fina Oil and Chemical Company

Elisa J. Grammer
Partner
Baller Hammett

Patricia A. Hammick
Vice President
Natural Gas Supply Association

Frank O. Heintz
Chairman
Maryland Public Service Commission

R. Skip Horvath
Vice President
Rate and Policy Analysis
Interstate Natural Gas Association
of America

Glen S. Howard
Partner
Sutherland, Asbill & Brennan

James R. Kremen
Technical Advisor to the Chairman
Federal Energy Regulatory Commission

Robert C. Krueger
Commissioner
Railroad Commission of Texas

Robert C. McHugh
Vice Chairman
KN Energy, Inc.

Kay C. Medlin
Vice President and General Counsel
Arkla Energy Marketing Company

Thomas J. Norris
Vice President
Rate and Regulatory Affairs
Tenneco Gas

Kenneth E. Randolph
Senior Vice President and General Counsel
Natural Gas Clearinghouse

William R. Shane
Indiana, Pennsylvania

Clark C. Smith
President
Coastal Gas Marketing Company

William H. Smith, Jr.
Chief
Bureau of Rate and Safety Evaluation
Iowa Utilities Board

Thomas J. Vessels
President
Vessels Oil & Gas Company

SPECIAL ASSISTANTS

Michael J. Armiak
Assistant Vice President
State Regulatory Relations
ANR Pipeline Company

L. Roy Kavanaugh
Director
Market Development
Tenneco Gas

Hugh D. Roberts
Regulatory Affairs Coordinator
Natural Gas Divison
Marathon Oil Company

Sherrie N. Rutherford
Assistant General Counsel
Enron Interstate Pipeline Company

Linda Silverman
International Energy Analyst
U.S. Department of Energy

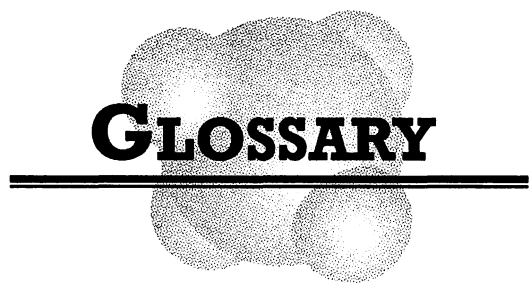
Acronyms and Abbreviations

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, creditworthy 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 Fed-

eral 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.



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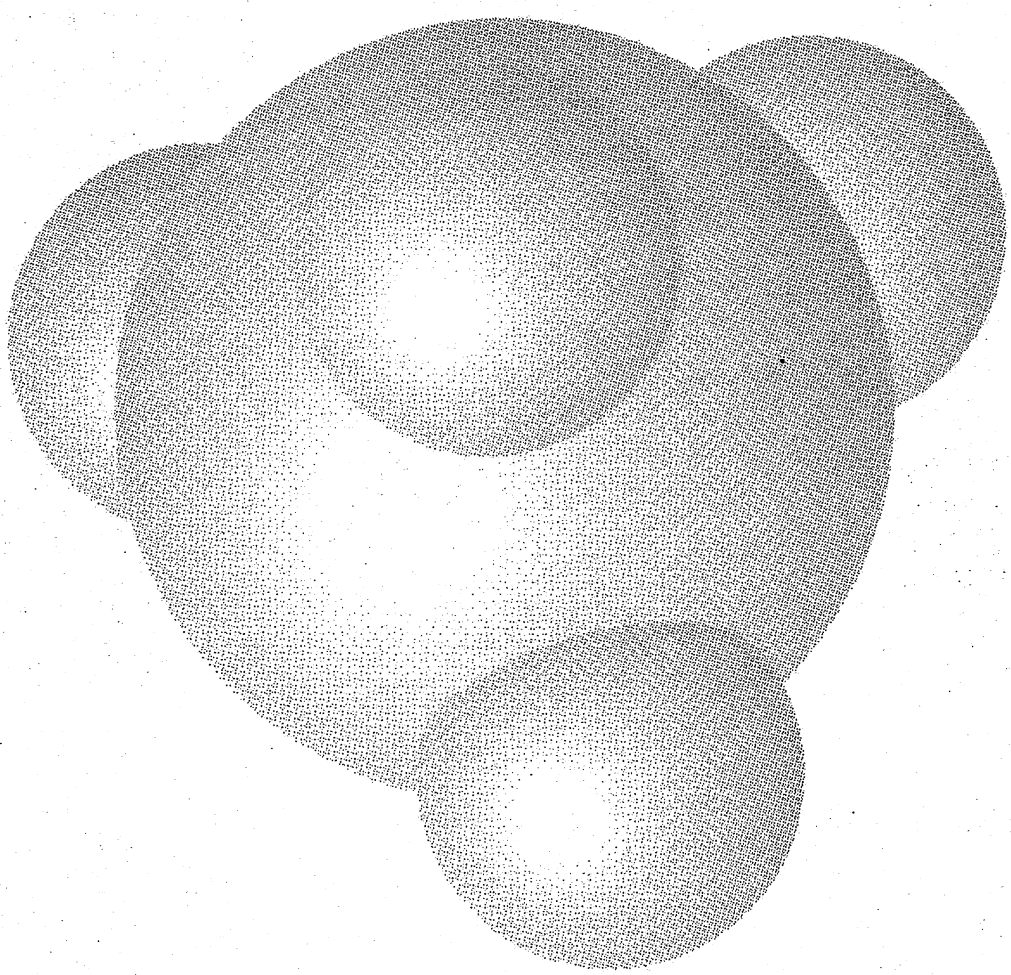
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