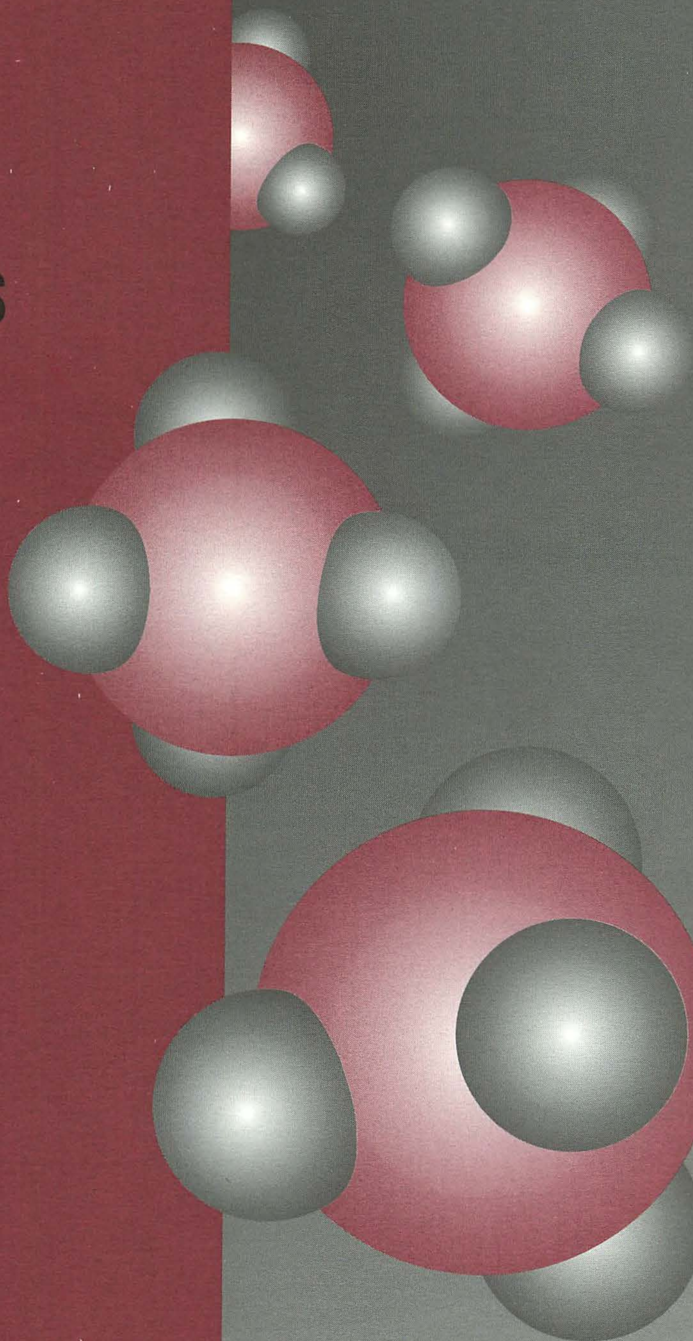
The Potential for Natural Gas in the United States

Demand and Distribution



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,

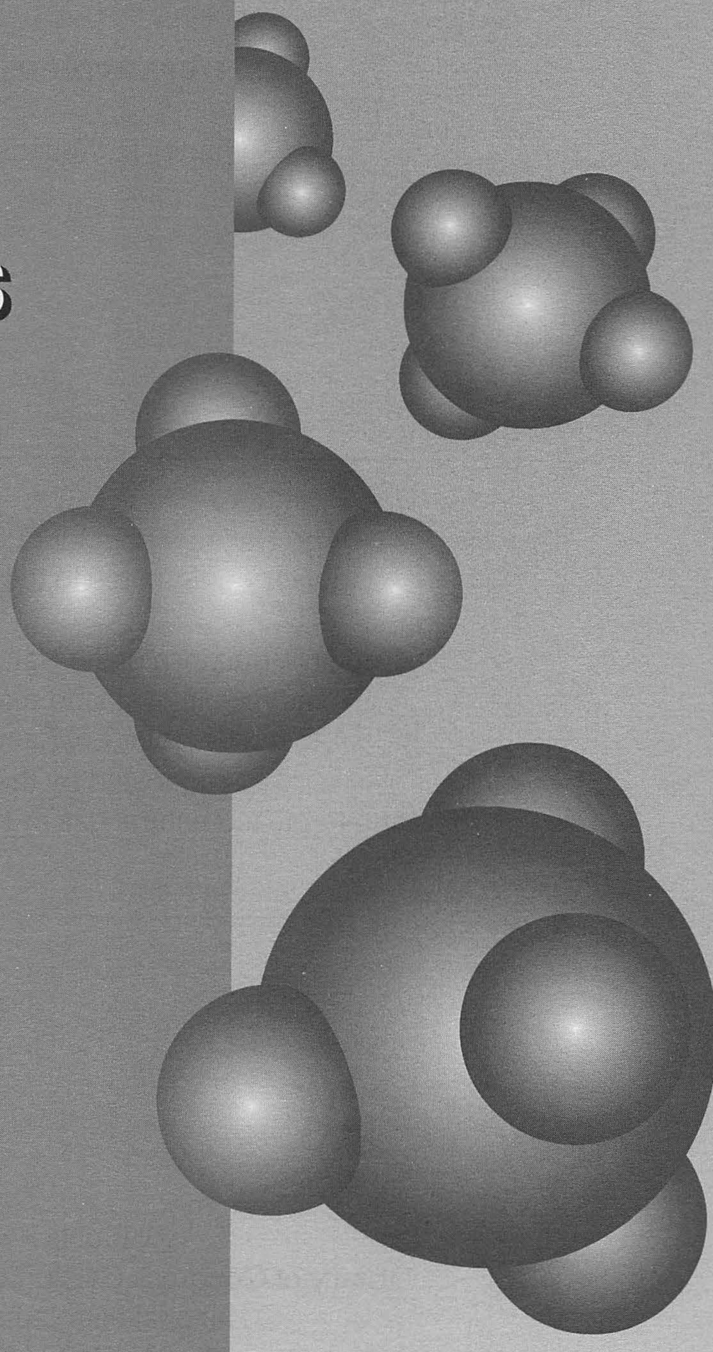
Ray L. Hunt

Ray L. Hunt
Chairman

Enclosure

The Potential for Natural Gas in the United States

Demand and Distribution



December 1992
National Petroleum Council

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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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TABLE OF CONTENTS

APPENDICES

SUMMARY

The Demand and Distribution Task Group is one of four such groups created by the Natural Gas Committee of the National Petroleum Council (NPC) to respond to the Secretary of Energy's request for a "comprehensive analysis of the potential for natural gas to make a larger contribution to the nation's energy supply and the President's environmental goal." The task group, composed of approximately 40 persons, included representatives of producers, interstate pipelines, local distribution companies (LDCs), and the federal government, as well as such associations as the Gas Research Institute, the American Gas Association, and the Edison Electric Institute. In addition, the electric utility industry was represented.

STUDY METHODOLOGY

The Demand and Distribution Task Group undertook three major responsibilities:

1. Development of ten regional reports assessing market and economic conditions, and enumerating both opportunities for an increase in gas consumption and constraints inhibiting such growth. (These regional reports are quoted throughout this volume, and can be obtained in their entirety from the NPC. (See order form at the end of this volume.)

2. Identification of the major growth opportunities for nationwide gas demand, the obstacles and constraints which could inhibit this growth, and the methods by which those obstacles might be overcome.

3. Development of assumptions and review of results of the NPC Reference Case scenarios for the period through the year 2010.

These analyses and activities provide the basis for this report. This Executive Summary extracts key findings, conclusions, and recommendations on natural gas demand. It specifically addresses the residential and commercial markets, the industrial market, the electric generation market, emerging technologies (including natural gas vehicles [NGVs]), and their commercialization, and other issues facing the gas industry.

GENERAL FINDINGS

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 1 and 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 1 contains a break-

TABLE 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.

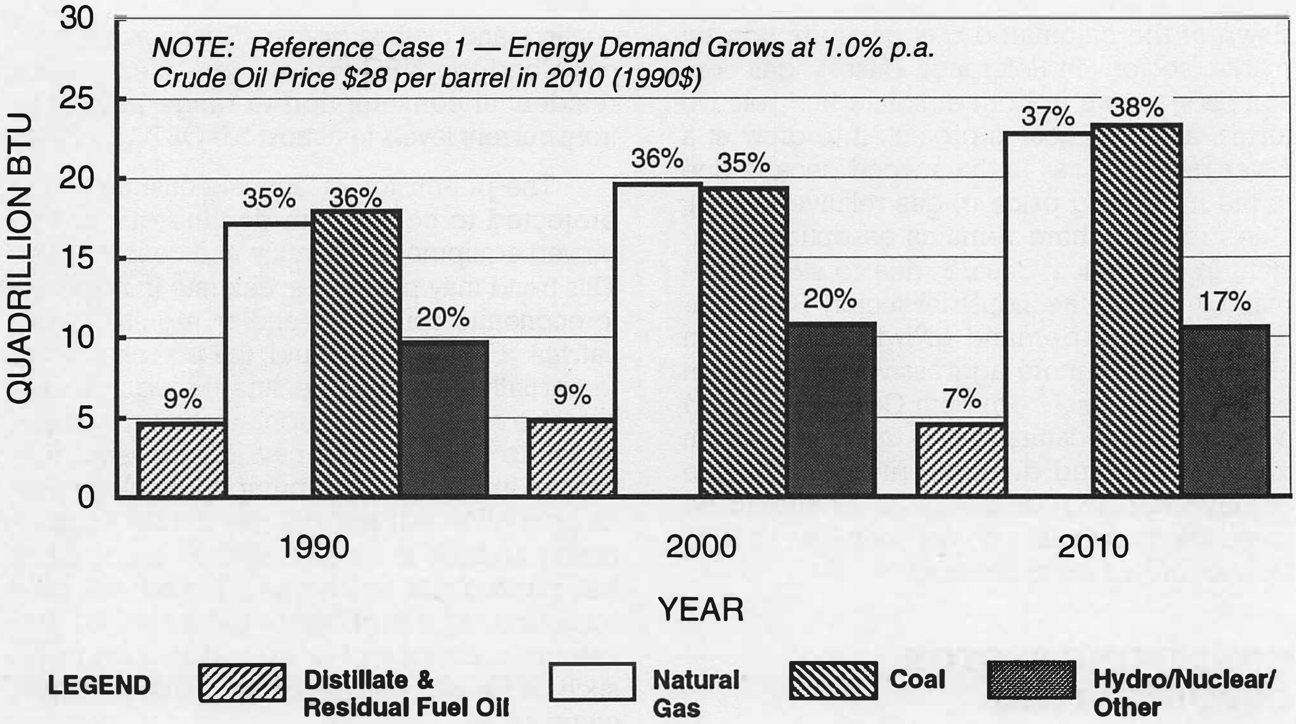

Figure 1. Primary Energy Consumption and Market Share—Reference Case 1.
(Excludes Coking Coal, Oil Feedstocks, and Liquid Transportation Fuels;
Gas Data Exclude Lease/Plant Fuel, Transmission Fuel, and Exports)

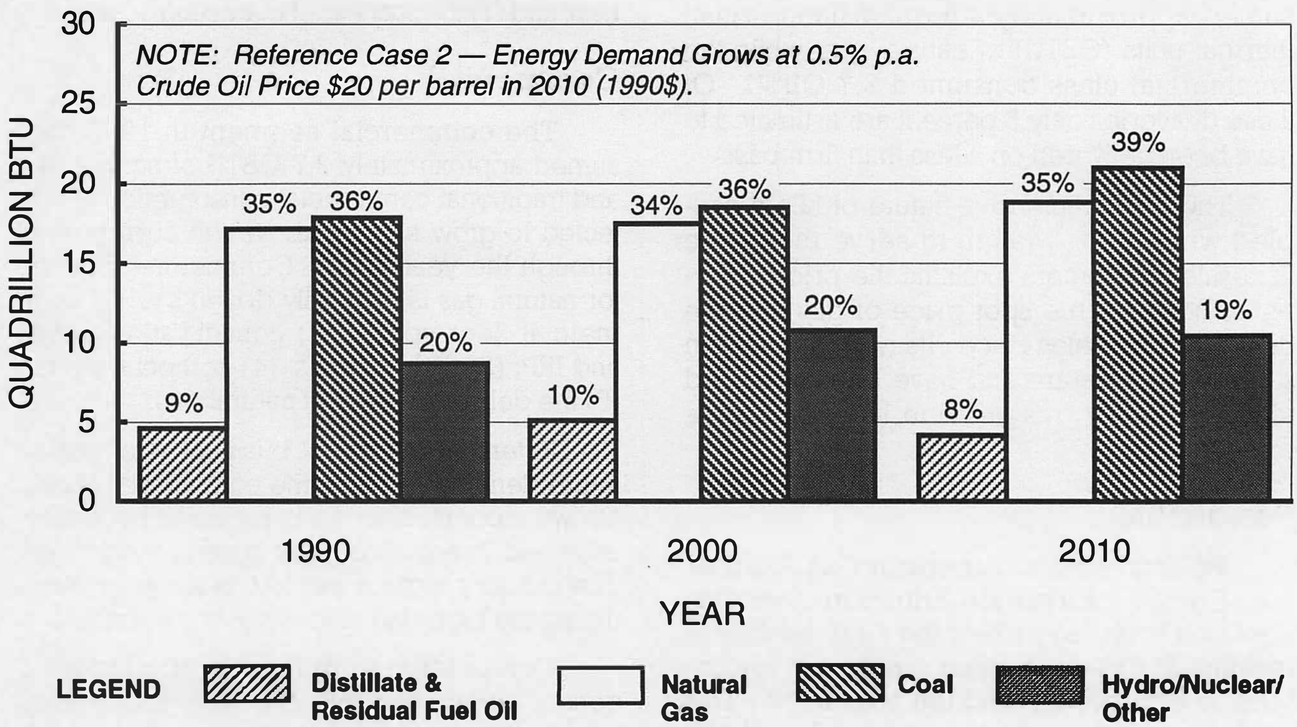

Figure 2. Primary Energy Consumption and Market Share—Reference Case 2.
(Excludes Coking Coal, Oil Feedstocks, and Liquid Transportation Fuels;
Gas Data Exclude Lease/Plant Fuel, Transmission Fuel, and Exports)

down 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 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 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 Seven, 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 ONE

BACKGROUND AND DISTRIBUTION ISSUES

HISTORICAL OVERVIEW

Natural gas has been consumed as a fuel in this country since 1816, when gas manufactured from coal was used to illuminate the streets of Baltimore, Maryland. Consumers of gas in the 1800s burned gas produced or manufactured locally, 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 end-use market decreased in importance. The production and consumption of manufactured gas steadily declined in light of the availability of the less expensive "natural" gas alternative. The gas market continued to evolve and grow over the next 50 years, in spite of major wars, economic recessions, and regulatory enactments. From a national consumption level of 2 TCF in 1930, annual gas consumption grew to a peak of 22 TCF in 1972, before artificially induced retrenchment—first in supply, then in demand—caused consumption to recede. The future demand for natural gas has grown brighter since the virtual deregulation of production occurred following the 1978 passage of the Natural Gas Policy Act (NGPA) and the opening of the nation's transmission systems.

Natural Gas Act of 1938

As already noted, the invention of seamless welded pipe made the long distance transmission of natural gas possible and provided interstate markets for the large gas discoveries of the 1920s and 1930s. To cover the "regulatory gap" thus created upstream from the state regulated local distribution companies, Congress passed the Natural Gas Act in 1938.

Phillips Decision

The Federal Power Commission (FPC, forerunner of the Federal Energy Regulatory Commission) did not regulate the price of gas at the wellhead in the years immediately following the passage of the Natural Gas Act. The Supreme Court ruled, however, in its 1954 *Phillips*[1] decision that the Natural Gas Act required regulation of the price of natural gas at the wellhead.

The FPC developed various schemes to regulate the wellhead price of gas, as the burden of regulating each individual gas contract on a cost-of-service basis was administratively overwhelming. The regulators erred on the side of low gas prices, and, 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 interstate gas prices stimulated demand, yet discouraged natural gas exploration activities. By the early 1970s, spot shortages of gas began to appear and industrial users became subject to frequent interruption. During the harsh winter of

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1 *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954).

1976-77, the artificially induced shortage had become severe, and gas deliveries throughout the Northeast, Midwest, and Mid-Atlantic states were, to varying degrees, curtailed.

Natural Gas Policy Act of 1978

The emergency of the winter of 1976-1977 produced an overall general consensus that legislative action was necessary to remedy natural gas shortages. With that consensus, and against a backdrop of competing interests, Congress produced an incredibly complex series of compromises that became the 1978 NGPA.

The objective of the NGPA and its companion legislation, the Power Plant and Industrial Fuel Use Act, was to raise gas prices in order to encourage gas production while restricting its consumption by non-core market segments. 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. What passed was a "phased decontrol" of a complex array of different categories of gas.

The higher prices for new gas after the passage of the NGPA did encourage the search for and production of new gas reserves. Interstate pipelines and local distribution companies (LDCs), inspired by a dread of continued shortages, hastened to contract for this supply regardless of cost. The higher gas prices, however, discouraged demand. The net effect of the reserve additions arising from the new drilling, the demand erosion from conservation due to higher prices, the restrictions on end-use gas consumption, and an economic recession, was that by the early 1980s the gas supply shortage had become a gas supply surplus. The prices being paid for gas by pipelines (and LDCs) under long-term contracts began to exceed the market clearing price of gas. Industrial customers who could switch to alternate fuels did so, thus further depressing gas demand. Proposals to allow access to spot market gas to serve industrial users that would otherwise switch to alternate fuels were proposed by the pipelines and approved by the Federal Energy Regulatory Commission (FERC) as "special marketing programs."

In a 1985 case before the D.C. Court of Appeals, *Maryland People's Counsel v. FERC*, it was found that such preferential access to spot market gas was discriminatory, and the FERC was directed to respond by providing non-discriminatory access. The FERC responded with Order 436. This order, issued in October of 1985, required that pipelines provide non-discriminatory access to transportation systems and services. As pipelines began to transport spot gas for resale customers under this order, they displaced their own sales gas, and their "take-or-pay" liabilities to producers,[2] already large, mushroomed.

FERC Orders 500 and 528

FERC Order 500 allowed pipelines to "direct bill" a portion of their take-or-pay costs to LDC customers on the basis of past purchase levels from the affected pipelines. Litigation between the D.C. Court of Appeals and the FERC, in which the Court, after having first invalidated the "direct bill" provision of Order 500 due to the retroactive nature of the direct bill, agreed to the substitute allocation method promulgated by the FERC in Order 528.

FERC Orders 636, 636A, and 636B

FERC Orders 636, 636A, and 636B virtually eliminate the pipeline merchant functions. This transfer of gas purchasing responsibilities suggests that the LDCs must enhance their gas supply market intelligence, contracting and contract administration skills, planning capabilities, and monitoring abilities. They must also adopt a least cost portfolio approach to gas purchasing to minimize risks and maximize value to their customers.

State regulators have now inherited the regulatory oversight responsibility for gas supply from the FERC. This task will require the regulators and LDCs to work together to evaluate risks, price trends, and security of supply and avoid pitfalls of hindsight regulation. Purchase gas adjustment rules may have to be de-

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2 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 it 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 bargain with producers on price because of the maximum lawful price caps. These take-or-pay obligations had been largely offset by minimum commodity bills to the pipelines' customers.

veloped that encourage creativity in supply portfolio development and open communication to maximize benefits for all concerned.

Conclusion

This history of market intervention is at the root of many of the marketing problems faced today by natural gas. Public [mis]perceptions of gas as a scarce and costly fuel, prone to deliverability problems and subject to regulatory snarl-ups, will be difficult but not impossible to overcome. This NPC study sets the stage for the gas industry, its regulators, and government to change the way of doing business and to create an environment where natural gas may flourish.

Figures 1-1 through 1-3 provide a historical perspective of the demand for natural gas. Figure 1-1 shows the historical breakdown of gas demand by market sector, while Figure 1-2 displays the total natural gas consumption over the same time period. Figure 1-3 illustrates the historical regional composition of end-use natural gas consumption.

BACKGROUND AND FUNDAMENTALS

In the gas industry, the "distribution system" is defined as that portion of the gas delivery pipeline network that is owned, operated, and maintained by LDCs.

Several important physical features of the upstream gas supply and delivery system may be helpful to understand before outlining the principal issues related to distribution systems.

Natural gas is produced from wells that are operated by "producers." A significant but declining portion of natural gas is produced from wells that also produce crude oil (called associated gas). In the early years of oil production, associated gas was often vented since it had no commercial value. Venting ended as soon as gas end uses and the pipeline infrastructure developed. In other cases, gas was and still is re-injected to maintain pressure and enhance oil production. Natural gas from a group of wells is pooled through a "gathering system" and "processed" before being delivered to the pipeline system (the "pipegate"). Processing includes: (a) removal and disposal of undesirable gases such as carbon dioxide, (b) separation for resale of hydrogen gas and natural gas liquids with commercial value, and (c) separation of undesirable "liquids" from the gas such as water.

This "dry gas" is then compressed at pressures ranging from 300 to 800 pounds per square inch and above, and delivered by

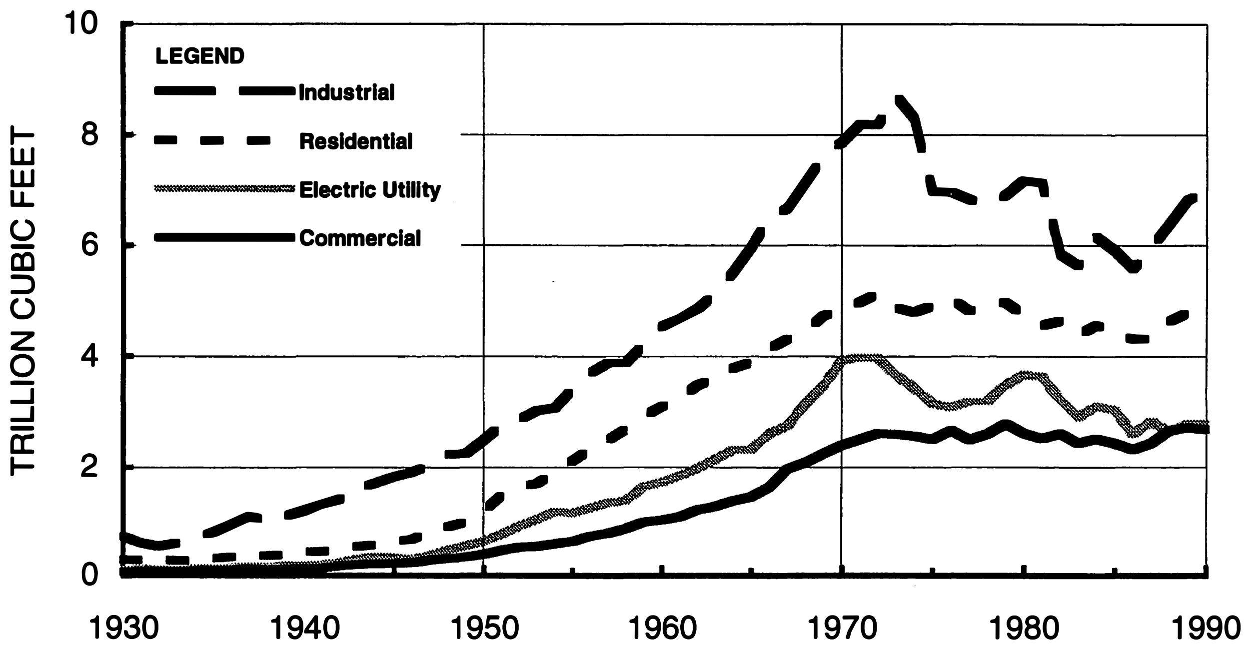


Figure 1-1. End-Use Consumption of Natural Gas by Sector—1930-1990.

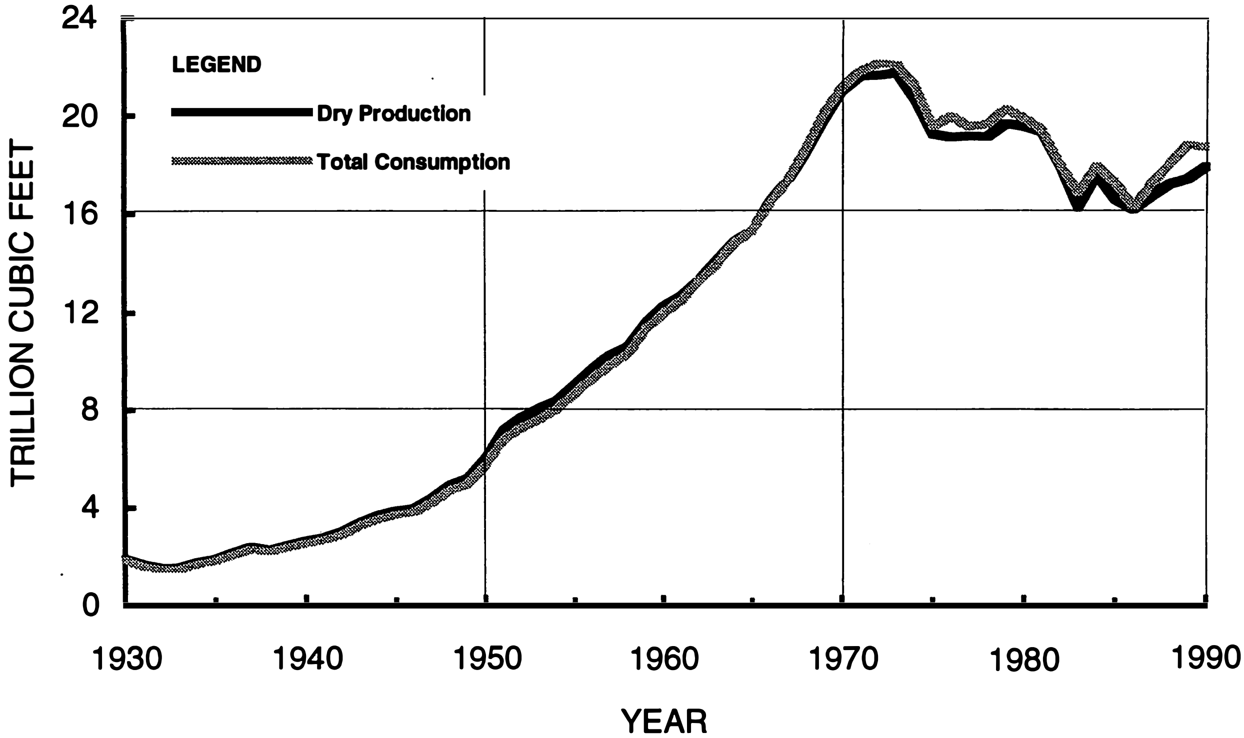
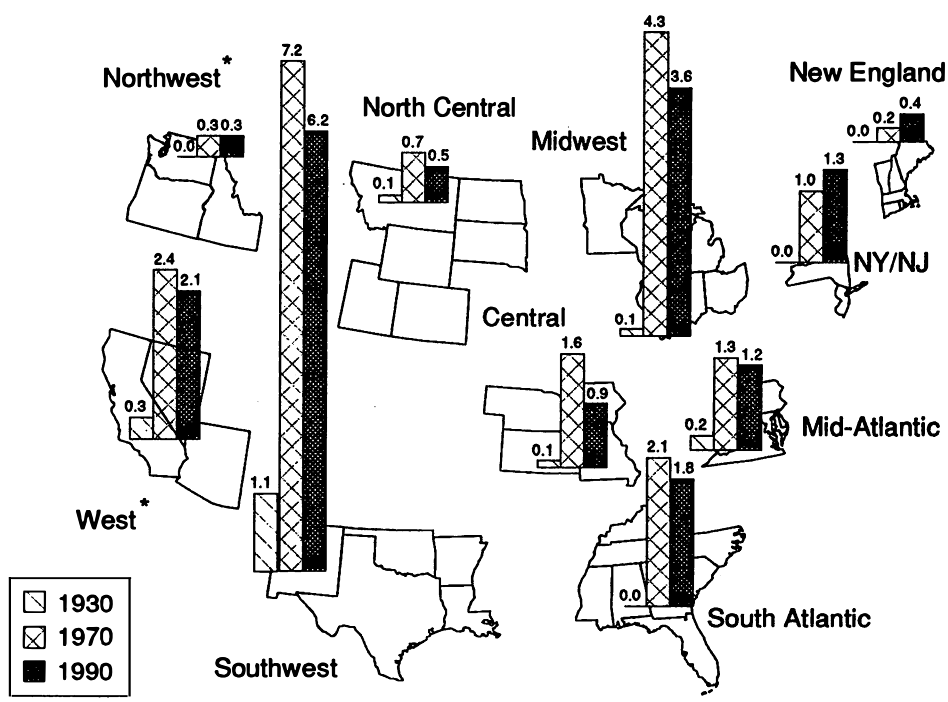


Figure 1-2. Natural Gas Consumption and Production—1930-1990.



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

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

pipeline companies to the demand centers (LDCs or direct sale customers). The actual gas molecules travel approximately 15 miles/hour in pipeline mains which usually range from 24" to 42" in diameter. Compressors usually use a portion of the gas to compress and transport the gas to its final destination (shrinkage). The physical point at which the gas is metered and an LDC normally takes legal possession of the gas from the pipeline company into its distribution system is called the "citygate." When pipeline companies finally deliver the gas to the citygate, the gas pressures are reduced somewhat (usually below 300 pounds per square inch) and the odorless natural gas is odorized before delivery into the distributor system "mains." Smaller service lines extending from gas mains deliver lower pressure gas to end-use customers. The service line pressures are usually very low for residential/commercial customers and higher for large volume industrial customers and electric generation steam units.

SERVICES PROVIDED BY LDCS

LDCs broadly categorize their sales and transportation service customers into two classes: "firm" and "interruptible." LDCs provide at least three types of services: sales (firm and interruptible), end-user transportation (firm and interruptible), and "balancing." A balancing service is usually associated with end-user transportation where the customer of the LDC is responsible for delivering gas to the citygate. In situations where the customer consumes gas in an amount unequal to that delivered into the distribution system on behalf of his account, a "balancing" service is required from the LDC to reconcile the difference.

Typically, firm sales customers (also known as the core market) comprise the group of customers for which no short-term alternative to gas service exists. These customers are dependent on the LDC to provide uninterrupted service, even under the most extreme of weather conditions. Due to the health and welfare aspects of core service, and due to the impact changes in rates or services can have on core customers, state Public Service Commission (PSCs) are particularly responsive to the needs of core customers.

The definition of "firm service" is evolving among some LDCs and PSCs in response to the changing conditions of the U.S. gas market. Firm service now includes services of durations less than 365 days per year. For example, some contracts are currently being written by gas utilities that guarantee 335 days of firm service to an electric utility or non-utility generator, while retaining rights to the capacity as needed to serve peak day needs of firm core customers for up to 30 days annually. Specification of the duration of firm service provides the needed assurance required by non-utility generators and other electric generators in order to take advantage of seasonal price variations. Such arrangements may become more common if seasonal pricing is permitted and encouraged.

Interruptible gas customers ("the non-core market") are those customers who are usually much more price sensitive and who receive a lower quality service in exchange for lower prices. The lower quality service is usually based on either: (a) a firm commitment for service when capacity is available, or (b) an interruption of service at or below some prescribed temperature which is set prior to the beginning of the winter season. The design concept behind interruptible service is that service to interruptible customers: (1) allows the LDC to "levelize" its throughput at a higher load factor, (2) provides some revenues that otherwise would not be realized, and (3) does not create a need for new peak day and peak season deliverability. It should be noted that interruptions based on the quality of service elected by the customer must be distinguished from "curtailments," which are unplanned interruptions of service inconsistent with the kind of service selected.

A majority of large LDCs have unbundled gas sales service and now offer a range of services such as gas transportation (firm and interruptible), contract storage, balancing, etc. These services allow end users, particularly large volume end users, to contract for only those services required to meet their needs. Service offerings at the LDC level will continue to evolve to meet customer needs and competitive pressures.

DESIGN OF DISTRIBUTION SYSTEMS

The sizing of LDC pipeline capacity is determined by the requirement that an LDC must satisfy all firm gas requirements on demand. In sizing LDCs' new and replacement mains and services, LDCs and their regulators have generally understood that system mains and services should be somewhat oversized to ensure reliability of service and allow for some foreseeable expansion. Some over-capacity is usually the rule rather than the exception. The extent of permitted over-capacity depends on the particular regulators and region of the country. The relative mix and magnitude of firm demand versus interruptible demand varies by region; such customer mix differences will also have an important bearing on whether the over-capacity with respect to firm requirements will suffice to cover interruptible load as well. For example, many utilities in New York and Michigan can provide year-round distribution service to all existing firm and interruptible customers as long as the gas can be delivered to the city gate. Some LDCs are not currently in a position to provide additional peak service beyond existing firm service.

Generally, distribution companies are required to build and maintain distribution system capacity (and plan and contract for adequate firm supplies and pipeline transportation capacity) sufficient to meet firm customer, peak day and peak season gas demand under severe, design weather conditions. In New York state, for example, the design criteria require that LDCs be able to satisfy all firm demand at temperatures last experienced during the winter of 1933-34—the coldest winter season this century in New York. Design weather supply planning criteria vary from state to state and from LDC to LDC.

DISTRIBUTION SYSTEM ISSUES

The principal issues related to distribution systems are discussed below.

Adequacy of Distribution Capacity

LDC distribution system capacity is currently designed to meet firm customer loads without exception under design weather conditions. The definition of design weather conditions varies by state as does the mix of customers served by gas within each state. Consequently, distribution system capacity is adequate to meet firm core loads, but may or may not be adequate to meet all interruptible gas customer load under design weather conditions.

Construction expenditures in the delivery infrastructure in the $6-10 billion range per year will be needed to accommodate the growing gas customers and demand anticipated in this report. Such expenditures are occurring today (over $9 billion in 1991 and over $10 billion projected for 1992) and will continue to occur to the extent necessary to ensure that the adequacy of the storage and delivery infrastructure will *not* be a constraint in the future. The recent history of the gas industry has demonstrated an ability of the industry to commit the capital necessary to expand the distribution and storage system to satisfy rapidly growing demand.

Physical Condition of the Distribution Systems

Distribution systems are in a state of constant maintenance and upgrade to ensure system reliability. However, differences among state PSCs and differences in the urgency for repairs in the distribution systems account for differences in allowed expenditures. No evidence was found of any national distribution system problems. However, the permitting and construction of new or replacement facilities is becoming more difficult and expensive as a consequence of various growth management, building code, and environmental requirements.

Cost Reductions and Efficiencies

In addition to providing natural gas procurement and transportation services for customers, LDCs are responsible for metering, billing, customer service, and energy-efficiency programs. The continuing challenge for LDCs is to seek opportunities to streamline processes or procedures, reduce costs, improve operating efficiencies, and expand needed service offerings. The benefit of these efforts will be increased customer satisfaction and more competitive natural gas services.

Incentive Rate Concepts

Cost-of-service regulation directly ties the rates or prices that can be charged for a service to the allowed costs of providing that service. As such it is intended to encourage the affected LDC to invest the money necessary to provide the highest quality service to the customer. Allowed costs include operating and maintenance costs, general and administrative costs, depreciation, interest, taxes, and return on capital.

Incentive rate structures are designed to counteract many of the deficiencies inherent in cost-of-service regulation. In so doing, however, they may create new problems of their own. Among the incentive rate mechanisms widely discussed are the following:

- ***Price Caps:*** Rates are initially determined based on cost of service, but periodically changed by a predetermined index.
- ***Zone of Reasonableness:*** A range of returns is established within which the company is encouraged to operate.
- ***Bounded Rates:*** Bounded rates establish an upper bound based on the marginal or replacement cost of the service and a lower bound based on some appropriate criteria. Since the company is free to charge any price within these boundaries, productive efficiency is achieved while simultaneously achieving allocative efficiency.
- ***Efficiency Gains:*** This is a sharing mechanism that, in general, focuses on parameters that are easily measurable, e.g., operating costs or throughput. The benefits or costs of any measurable change in these parameters are shared among the customer and the company on a predetermined basis.
- ***Incentive Rates of Return:*** The regulated company is awarded an incentive return, e.g., a one-quarter percent higher return on equity, for achieving a specific performance level.

Incentive regulation is discussed in Volume V – Regulatory and Policy Issues.

CHAPTER TWO
RESIDENTIAL SECTOR

At the request of the National Petroleum Council, an analysis of the demand for natural gas by the residential sector was conducted. Input on the subject was obtained from the Regional Reports of the Demand and Distribution Task Group; these reports were generally developed by participants from the local gas distribution companies (LDCs) serving the regions. Additional information was also obtained from governmental, industry, and trade sources.

Residential gas consumption includes single family and multi-family units as well as mobile homes. Single family homes include both townhouses and detached houses. Multi-family units include apartments, condominiums, and various other types of multi-unit arrangements. Table 2-1 presents an Energy Information Administration table summarizing residential energy consumption, based on information obtained from *Housing Characteristics 1990.*[1]

There are some significant differences between the space conditioning (heating) equipment and consumption characteristics of the single family and multi-family sectors. Townhouses and detached houses are typically served by individual appliances for space conditioning and hot water purposes. Energy interaction between units tends to be minimal. A single family Heating, Ventilating, and Air Conditioning system (HVAC) will typically consist of relatively simple duct work and a furnace or boiler. In comparison, both central systems and individual systems are used in the case of the multi-family sector. These multi-family HVAC systems tend to be more complex than is the case for single family housing, with a variety of fans, pumps, control systems, duct work, and equipment options being possible. The energy consumption characteristics of multi-family units frequently involve interaction among units in terms of heat flows. Accordingly, an analysis of a multi-family building will focus to a greater degree on heat flows, equipment options, and interactions than will the analysis of a residential single family unit. Also, in multi-family buildings the installation of central space heating and cooling systems is now declining in preference relative to individual systems. In many cases, owners and developers are installing individual systems for each dwelling unit to shift the cost of the utility from the owner to the occupier of the space.

RESIDENTIAL: AN OVERVIEW

Energy Consumption and Expenditures

There appears to be general agreement that regardless of the increased focus on marketing activities, changes in the residential demand for natural gas will be relatively minimal in forthcoming years as conservation offsets this increased growth. Table 2-2 and Figures 2-1 and 2-2 summarize a number of recent residential projections. The outlook for residential gas consumption is basically projected to be constant.

[1] Energy Information Administration, *Housing Characteristics 1990*, DOE/EIA-0314(90).

TABLE 2-1

PRELIMINARY ESTIMATES OF ENERGY CONSUMPTION AND EXPENDITURES FROM THE 1990 RESIDENTIAL ENERGY CONSUMPTION SURVEY

Type of Housing Unit and Energy Source	Households Using the Energy Source (Million)	Total Consumption (Quadrillion BTU)	Total Expend-itures (Billion Dollars)	Average Consumption per Household (Million BTU)	Average Expenditures per Household (Dollars)
All Households	94.0	9.3	110.5	98.6	1,176
Electricity	94.0	3.0	71.6	32.3	761
Natural Gas	57.7	4.9	27.5	84.9	476
Fuel Oil	11.7	1.0	7.7	84.0	654
Kerosene	5.3	0.1	0.6	11.5	109
LPG	8.2	0.3	3.2	35.2	390
Single-family	64.4	7.2	85.2	111.3	1,323
Electricity	64.4	2.4	55.6	37.0	864
Natural Gas	39.5	3.8	20.6	95.0	521
Fuel Oil	8.2	0.8	6.1	92.4	736
Kerosene	4.1	*	0.3	8.6	82
LPG	6.2	0.2	2.5	37.6	411
Mobile Home	5.2	0.4	5.3	77.3	1,008
Electricity	5.2	0.2	3.5	31.1	674
Natural Gas	2.0	0.2	0.8	74.6	397
Fuel Oil	0.4	*	0.2	49.5	409
Kerosene	0.9	*	0.2	24.8	233
LPG	1.7	0.1	0.6	29.7	345
Multi-family	24.4	1.7	20.1	82.3	822
Electricity	24.4	0.5	12.4	19.9	509
Natural Gas	16.2	1.0	6.1	61.6	374
Fuel Oil	3.1	0.2	1.47	65.6	463
Kerosene	0.3	†	†	†	†
LPG	0.4	*	0.1	19.4	254

Data in this table are representative of the total U.S.

These data will differ from similar data collected on EIA's supply surveys because of differences in certain survey and/or statistical methodologies between the *1990 Residential Energy Consumption Survey (RECS)* and the supply surveys. For a more detailed discussion of these differences, see Energy Information Administration, *Housing Characteristics 1990*, DOE/EIA-0314(90).

* Less than 0.05.

† Data withheld because the observations were insufficient in the statistical sample to provide meaningful data.

SOURCE: Preliminary data. Energy Information Administration, Office of Energy Markets and End Use, Forms EIA-457 A through G of the *1990 Residential Energy Consumption Survey (RECS)*.

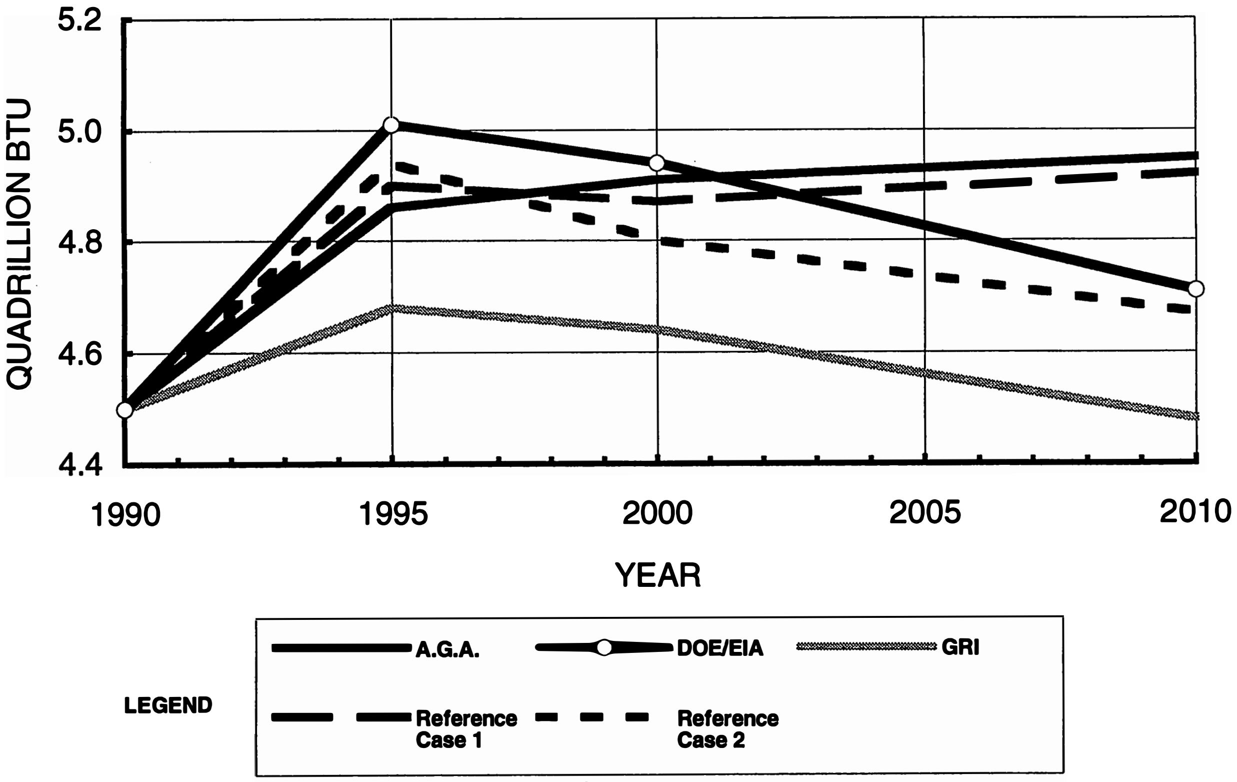
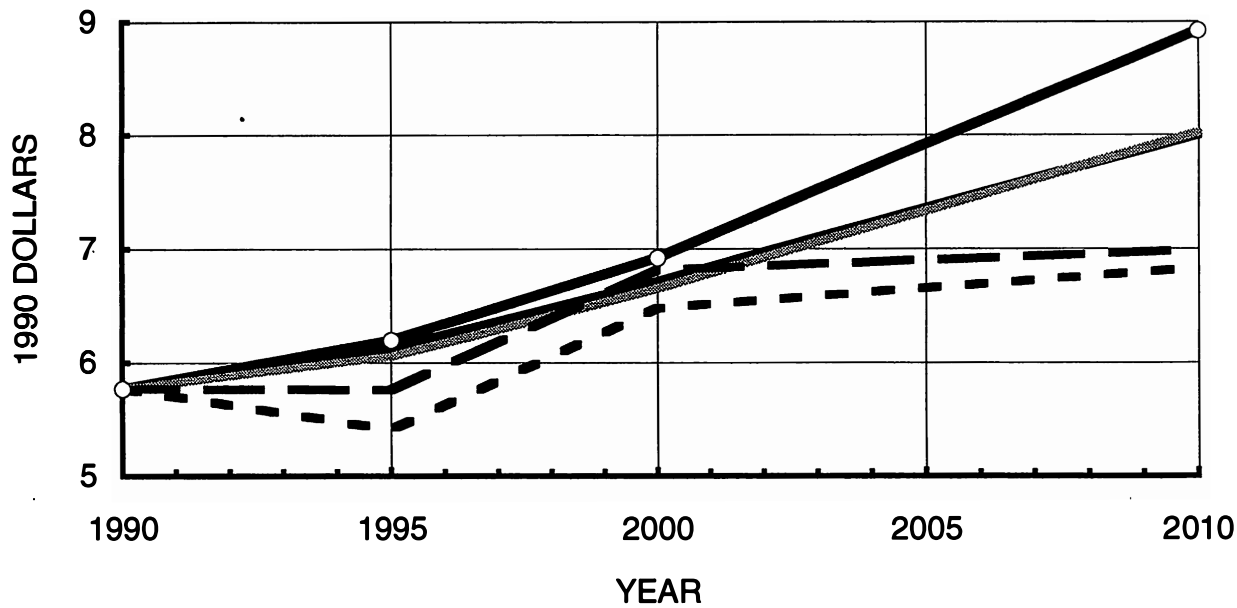


Figure 2-1. Residential Gas Demand Projections.



SOURCES: AGA: American Gas Association, TERA Base Case 1992.
EIA: Energy Information Administration, "Annual Energy Outlook 1992."
GRI: Gas Research Institute, GRI Baseline "Projection of U.S. Energy Supply and Demand, 1992 Edition (August 1991)."
NPC: National Petroleum Council.

Figure 2-2. Residential Gas Price Projections.

TABLE 2-2

RESIDENTIAL GAS DEMAND AND PRICE PROJECTIONS
(Quadrillion BTU and 1990 Dollars per MCF, Delivered)

	1990*		1995		2000		2010	
	Demand	Price	Demand	Price	Demand	Price	Demand	Price
AGA	4.50	$5.77	4.86	$6.13	4.91	$6.71	4.95	$8.00
EIA	4.50	$5.77	5.01	$6.20	4.94	$6.92	4.71	$8.92
GRI	4.50	$5.77	4.68	$6.06	4.64	$6.65	4.48	$8.02
Reference Case 1	4.50	$5.77	4.90	$5.76	4.87	$6.81	4.92	$6.99
Reference Case 2	4.50	$5.77	4.94	$5.41	4.80	$6.48	4.67	$6.83

* 1990 figures are not weather normalized

SOURCES: AGA: American Gas Association, TERA Base Case 1992.
EIA: Energy Information Administration, *Annual Energy Outlook 1992.*
GRI: Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1992 Edition (August 1991).*
NPC: National Petroleum Council.

Changes in gas demand within the residential sector will be a function of: (1) the effects of energy efficiency trends—due to Integrated Resource Planning (IRP) and equipment efficiency improvements; (2) the effect of price elasticity; (3) the level of new construction; (4) the relative market share that gas is able to capture; (5) new technologies; (6) possible fuel substitution in the equipment replacement markets; and (7) the success of marketing activities.

Residential Growth Rate Summary

During the 1980s the number of single family residential housing units nationally grew at a rate of 1.01 percent per year.[2] Current forecasts for the increase in the number of new residential units over the next 20 years are in the neighborhood of 1 percent per year. Offsetting the projected growth in gas demand due to the growth in the number of households is the decline in the average gas consumption per household, recently at a rate of 2.1 percent per year over the time period 1980 to 1990. Table 2-3 summarizes housing and consumption data in recent years by NPC region. Attached in Appendix D are graphs of housing and consumption by NPC region. The narrative will discuss uncertainties related to various projections.

Historical Prices and Consumption

Some analysts predict a continuation of the decline in energy use per household, based on continued reactions to historical price trends and in light of increasing efforts in Demand Side Management programs and IRP[3] by gas utilities. Natural gas prices in recent years have declined in real terms relative to the early 1980s. The data in Table 2-4 and Figure 2-3 provide a history of gas prices. Although there has been a decline in gas costs in recent years, conservation per household appears to have continued, possibly in response to the higher prices of the early 1980s accompanied by the introduction of higher efficiency gas equipment and mandated equipment minimum efficiency requirements. An alternative view would conclude that the pace of efficiency improvements will decline, due to much of the potential for efficiency improvements in the existing housing stock having already been realized. Consumption per customer is presented in Figure 2-4. It should be noted that

[2] Energy Information Administration, *Housing Characteristics 1990*, DOE/EIA-0314(90), Pg X.

[3] Integrated Resource Planning is also denoted by Least Cost Planning (LCP).

TABLE 2-3

RESIDENTIAL GAS DEMAND: IMPORTANT DRIVERS CONTINENTAL UNITED STATES

Year	Heating Degree Days	Consumption per Customer (MCF)	Bill per Customer (1990$)	Average Price (current$/MCF)	Average Price (1990$/MCF)	Number of Gas Households (Thousands)	Number of Households (Thousands)
1967	4,746	118.4	460.1	1.04	3.89	36,425	59,510
1968	4,805	119.4	442.8	1.04	3.71	37,248	61,018
1969	4,868	124.0	440.5	1.05	3.55	38,082	62,337
1970	4,794	125.2	438.6	1.09	3.50	38,589	63,538
1971	4,667	126.5	443.3	1.15	3.50	39,249	65,195
1972	4,847	128.4	453.3	1.21	3.53	39,860	67,110
1973	4,420	120.0	422.2	1.29	3.52	40,622	68,803
1974	4,532	115.3	414.7	1.43	3.60	41,487	70,398
1975	4,589	118.4	464.2	1.71	3.92	41,491	71,910
1976	4,868	122.3	522.5	1.98	4.27	41,210	73,606
1977	4,739	116.4	552.4	2.35	4.75	41,336	75,187
1978	5,111	117.0	561.7	2.56	4.80	41,812	77,005
1979	4,929	114.4	587.2	2.98	5.13	43,322	78,562
1980	4,858	107.7	624.2	3.68	5.80	44,054	79,965
1981	4,653	101.1	621.0	4.29	6.14	44,858	81,691
1982	4,753	103.6	723.6	5.18	6.98	44,592	82,489
1983	4,758	96.9	761.8	6.07	7.86	45,075	83,160
1984	4,647	99.7	757.5	6.13	7.60	45,576	84,713
1985	4,772	95.6	700.7	6.13	7.33	46,236	86,052
1986	4,430	91.9	625.1	5.84	6.80	46,779	87,233
1987	4,454	90.4	566.1	5.55	6.27	47,612	88,339
1988	4,798	95.4	567.8	5.47	5.95	48,379	89,707
1989	4,875	96.9	568.8	5.64	5.87	49,213	90,947
1990	4,127	87.4	503.1	5.76	5.76	50,086	91,402

Volume and price data derived primarily from the supply survey Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition." These data will differ from similar data collected in EIA's *Residential Energy Consumption Survey (RECS)* because of differences in survey and/or statistical methodologies. For a more detailed discussion of these differences, see Energy Information Administration, *Housing Characteristics 1990*, DOE/EIA-0314(90).

SOURCE: Energy Information Administration, *Natural Gas Annual 1990 Volume II* (DOE/EIA 0131(90)/2, Dec. 1991), Tables 15 & 17; *Economic Report of the President*, February, 1992, Table B-3; U.S. Dept. of Commerce, Bureau of the Census.

TABLE 2-4
RESIDENTIAL GAS DEMAND: SIGNIFICANT FACTORS
CONTINENTAL UNITED STATES

	1975	1980	1985	1990
REGION 1				
population	12,163	12,348	12,657	13,207
households	4,086	4,362	4,683	4,943
sales(MCF)	1,438,098	1,501,317	1,569,718	1,758,004
gas % of total energy	15.80	18.50	19.70	20.60
avg. gas price	7.25	8.71	9.67	7.88
consumption per customer	86.7	91.3	90.1	92.9
REGION 2				
population	25,341	24,923	25,307	25,720
households	8,773	8,889	9,233	9,434
sales(MCF)	4,659,258	4,816,722	4,855,845	5,249,374
gas % of total energy	30.70	34.00	34.90	36.90
avg. gas price	5.92	7.85	9.16	7.09
consumption per customer	84.1	89.3	84.3	86.4
REGION 3				
population	24,228	24,610	25,140	25,916
households	8,092	8,690	9,184	9,723
sales(MCF)	4,713,389	4,916,787	4,346,748	4,252,757
gas % of total energy	30.20	29.00	26.80	25.00
avg. gas price	4.57	6.24	8.21	6.59
consumption per customer	116.3	118.9	103.8	96.4
REGION 4				
population	35,853	38,880	42,068	44,708
households	11,708	13,740	15,411	16,929
sales(MCF)	3,601,518	3,677,706	3,212,483	3,393,829
gas % of total energy	16.80	14.60	12.20	11.40
avg. gas price	3.54	5.67	7.27	6.12
consumption per customer	94.1	88.1	71.4	66.3
REGION 5				
population	45,058	45,759	45,840	46,384
households	14,933	16,098	16,560	17,244
sales(MCF)	16,713,108	16,894,075	15,302,782	14,825,696
gas % of total energy	46.40	47.50	45.90	44.50
avg. gas price	3.62	5.42	7.08	5.07
consumption per customer	160.4	152.1	133.9	119.7

	1975	1980	1985	1990
REGION 6				
population	22,549	25,050	27,992	28,218
households	7,314	8,717	9,832	10,210
sales(MCF)	4,945,276	4,607,037	4,243,678	4,101,666
gas % of total energy	34.70	27.60	23.30	21.40
avg. gas price	3.19	4.95	6.48	5.54
consumption per customer	98.2	83	71.5	68.2
REGION 7				
population	11,513	11,765	11,970	11,950
households	3,998	4,289	4,435	4,572
sales(MCF)	4,097,575	3,712,911	3,421,858	3,091,607
gas % of total energy	44.90	39.50	38.20	34.50
avg. gas price	3.07	4.68	6.07	4.9
consumption per customer	148	125.9	113	97.6
REGION 8				
population	6,272	6,952	7,607	7,605
households	2,048	2,431	2,695	2,794
sales(MCF)	2,224,243	2,013,061	2,106,591	1,885,539
gas % of total energy	48.10	43.50	40.50	36.10
avg. gas price	2.78	4.85	6.06	4.79
consumption per customer	157.9	125.1	113.8	95.5
REGION 9				
population	24,443	27,186	30,488	34,627
households	8,605	9,891	10,985	12,216
sales(MCF)	6,940,284	5,857,710	5,863,617	5,768,278
gas % of total energy	52.40	43.10	40.40	37.10
avg. gas price	3.62	5.6	6.95	5.83
consumption per customer	99.8	74.6	69.1	60
REGION 10				
population	6,783	7,709	8,098	8,716
households	2,354	2,857	3,038	3,336
sales(MCF)	787,307	568,422	641,663	744,669
gas % of total energy	26.60	9.70	9.80	11.40
avg. gas price	5.11	8.45	8.07	5.43
consumption per customer	120.6	81.8	85.8	80.5

population, households, & sales = thousands
avg. gas price = 1990$/MCF
consumption per customer = MCF

NATIONAL	1975	1980	1985	1990
population	214,203	225,182	237,167	247,051
households	71,911	79,964	86,056	91,401
sales(MCF)	50,120,056	48,565,748	45,564,983	45,071,419
gas % of total energy	34.76	32.22	30.08	28.44
avg. gas price	3.82	5.8	7.33	5.76
consumption per customer	118.4	107.7	95.6	87.4

National totals do not include Alaska and Hawaii.

SOURCE: U.S. Department of Commerce, Bureau of the Census; Energy Information Administration, "Natural Gas Annual, 1990 Volume II," (DOE/EIA -0131(90)/2, December 1991), Tables 15 & 17; Energy Information Administration, "State Energy Data Report Consumption Estimates 1960-1990," DOE/EIA-0214(90); Economic Report of the President, Feb. 1992, Table B-3; Energy Information Administration, "Monthly Energy Review June 1992," DOE/EIA—0035(92/06), Table A5.

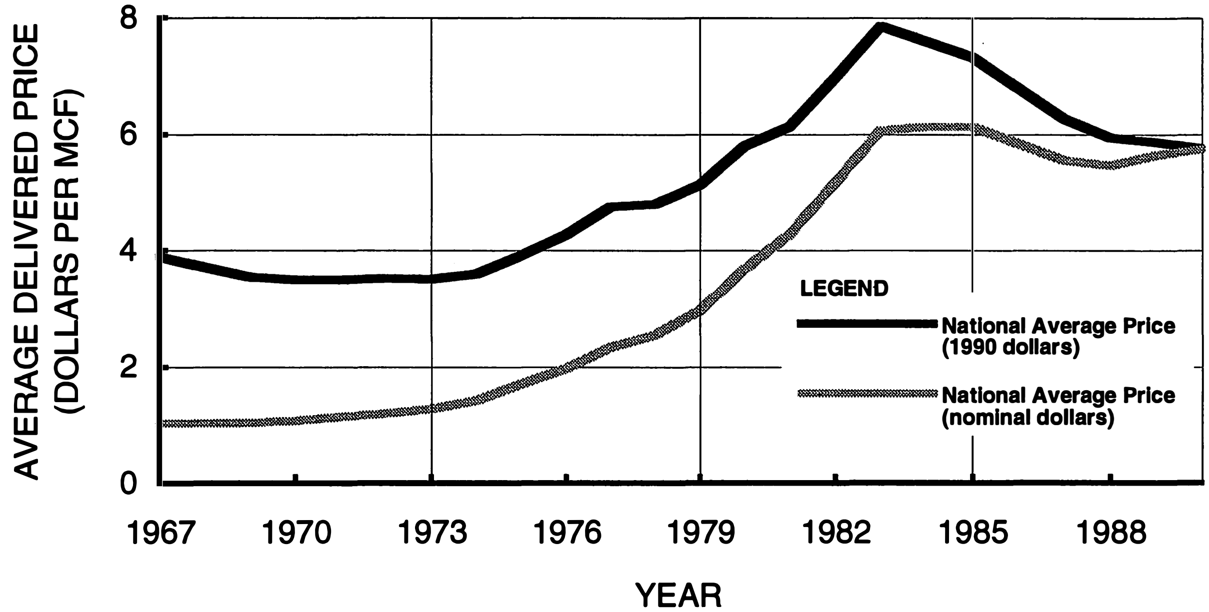
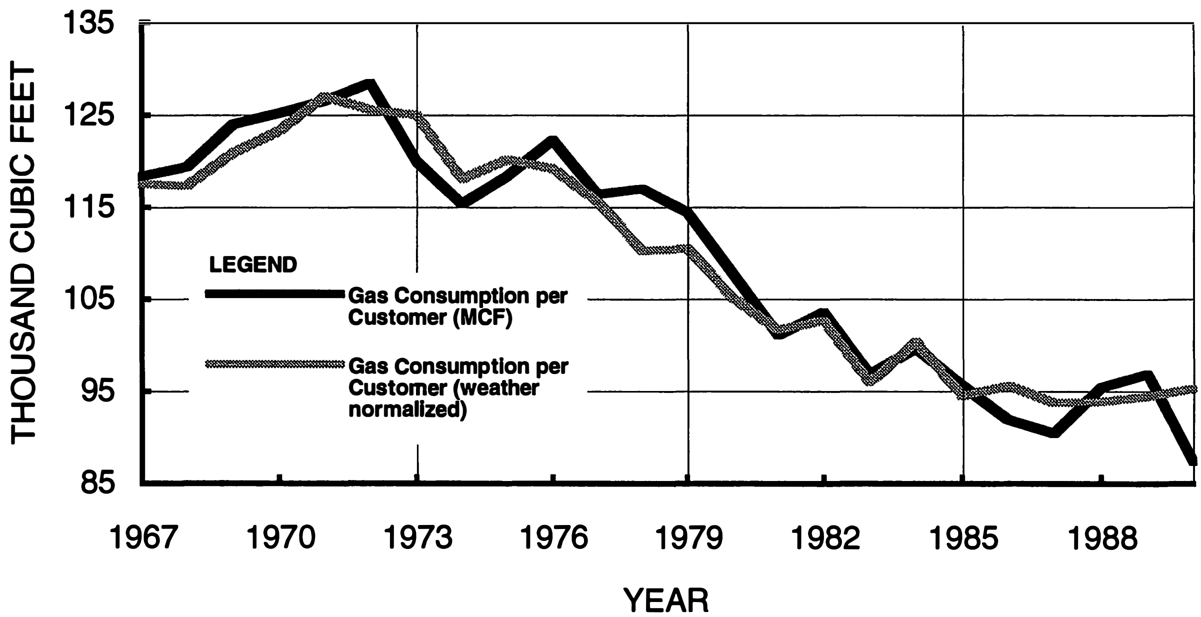


Figure 2-3. National Residential Natural Gas Prices.



SOURCE: Energy Information Administration, "Natural Gas Annual 1990 Volume II" (DOE/EIA 0131(90)/2, December 1991), Tables 15 &17; "Economic Report of the President, February, 1992," Table B-3.

Figure 2-4. National Residential Consumption per Customer.

consumption data have not been weather normalized and recent warmer than normal winters have influenced consumption patterns. Appendix D displays average price graphs by NPC region.

Market Share Outlook

Prior to the general moratorium on new residential gas hook-ups of the 1970s, natural gas was the predominant residential fuel in many areas of the country. During the gas moratorium there was a reliance on oil heating, and electric heating achieved increased acceptance. Since 1981, the market share of natural gas in new homes improved dramatically, returning to the levels achieved in the late 1960s and early 1970s. Still, the improvement and increased market penetration of the electric heat pump created a major competitor for natural gas in many areas of the country. There is currently a high level of competition between electricity and natural gas for market share in the new construction single- and multi-family residential market. However, natural gas still enjoys a substantial price advantage.

The uncertainty of residential projections of market share for gas in new construction are a function of the relative heating costs of gas and competing fuels, available technologies, technological change, market mix (single family detached, apartments, condos, townhouses, etc.), and consumer preferences. In addition to the new construction single family market, opportunities for additional residential space heating demand include conversions from another fuel and increased penetration of existing usages. Some gas utilities are experiencing a significant level of conversions from oil. Depending on modeling assumptions, one can show a slow increase or a slow decrease in consumption; however, neither case would be dramatic.

Technological Advances

Technological changes may impact the competitive position of natural gas space heating. The introduction of a residential gas-fired heat pump to the single family market, if successful, could capture some load that currently is lost to the electric heat pump. A gas heat pump would decrease winter load, would increase summer load, and might increase consumer preferences for gas. Other technological changes include higher efficiency boilers and furnaces in equipment serving both single family and multi-family markets. For example, advances have been made in recent years using combination heating and water heating equipment oriented towards the townhouse market. This design uses a water heater to supply not only hot water but also to supply heat using a hot water coil in an air handler.

Finally, increased penetration of water heating, cooking, clothes drying, and gas logs may be possible in some markets. There are also, however, miscellaneous technologies that could cut into natural gas market share. Two examples are: halogen cooking, which has recently entered the market, and microwave dryers, which currently are in the prototype stage with limitations (e.g. cost, metal on clothes), but may become popular. Chapter Seven (New Technology) discusses technological changes in detail.

Constraints to Increased Market Penetration—Single Family

Constraints to increased residential single family gas consumption include energy efficiency improvements, first costs of new technologies, the cost of new hook-ups, and the lack of previous natural gas consumption/familiarity, which results in continued consumption of alternative fuels. It appears likely that conservation will continue as the existing stock of residential gas appliances are replaced with new, high-efficiency gas appliances. In order to maintain residential market demand, the following are needed: (1) increased penetration in the new construction market; (2) retention in the replacement market; (3) market enhancement, i.e. additional burnertip appliances with current customers; and (4) some fuel substitution in the replacement market. Absent such new demand, throughput will decrease while fixed costs remain constant. This leads to increased rates and decreased competitiveness. The increase in the number of burnertips allows current customers to cover current costs, and "true growth" will result in additional hookups rather than that load being used to offset attrition/energy efficiency improvements. This scenario provides a win-win position for both the consumer and the gas industry.

New hook-ups require major investments in terms of services, meters, and mains. This is investment capital that the companies need to provide up front in order to provide service, and highlights the need for a financially viable industry.

Multi-Family Applications

Natural gas plays an important role in multi-family applications. Table 2-1 indicates that the multi-family gas consumption is 20 percent of the overall residential sector gas consumption. There are significant differences between single family and multi-family applications. In general, energy consumption in multi-family space is more dependent on the installed equipment than is the case for residential single family detached and townhouse units. In the case of central boilers for heating and hot water applications, the choice of cycling and control systems can have a significant impact on energy consumption. Energy flows between multi-family units can also have an impact on consumption. In contrast, building shell characteristics may be less important (but not unimportant) than is the case for residential single family units.

Reference Sources

The analysis in this chapter draws on two major sources of information: nationally available statistics, generally obtained from the Energy Information Administration and the American Gas Association, and the reports of each of the ten Regional Demand and Distribution Task Groups.

THE RESIDENTIAL SECTOR: EIA INFORMATION

Housing Characteristics and Related Statistics

The Energy Information Administration has issued a number of editions of its housing characteristics report; the eighth edition is *Housing Characteristics 1990*, based upon data collected by the *1990 Residential Energy Consumption Survey (RECS)*. Over 5,000 households were surveyed, as representative of the characteristics and energy consumption of the 94 million households nationwide.

> Perhaps the most significant finding is that the characteristics of *new* housing (built between 1988 and 1990) are changing relative to housing built since the 1970s. *New* housing is on average larger, more energy efficient, and most likely gas heated rather than electrically heated, but these changes were not large enough to affect the national-level shares for natural gas and electricity. This finding shows that even though lower energy prices may have lessened somewhat the economic incentives for change, the new energy programs of the 1980s are changing the nature and consumption patterns of housing in the United States.[4]

The report presents a number of conclusions related to natural gas:

- 55 percent of households use natural gas for space heating, and 53 percent for water heating, unchanged from 1980.[5]
- The growth in natural gas availability has lagged housing growth: The proportion of households reporting that natural gas was available in the neighborhood or that were already connected to a gas line decreased from 76 percent in 1981 to 72 percent in 1990. The report notes that 81 percent of older homes (built before 1940) have natural gas available. However, for homes constructed during the 1980s gas availability was only 50 percent. Current availability is 55 percent for new construction. This presents evidence that natural gas distribution systems have not fully expanded into existing neighborhoods, providing significant potential for future electric and oil conversions.[6]
- There is, according to the study, a significant potential for increased use of natural gas. Of the 57.5 million households that were connected to natural gas in 1990, the

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[4] Energy Information Administration, *Housing Characteristics 1990*, DOE/EIA-0314(90), "Residential Energy Consumption Survey," May 1992, Pg IX.

[5] Ibid., Pg X.

[6] Ibid., Pg XI.

study concluded that 6 million *did not* use it for space heating, 7.7 million *did not* use it for water heating, and 24 million *did not* use it for cooking. Another 10 million households had natural gas available in the neighborhood but were not connected to it.[7]

Table 2-5, taken from the EIA report, indicates that a number of houses either do not have gas but are on or near gas mains; or do have gas but do not use it for a major end use, such as heating, water heating, or cooking.

Conversion Potential

Current residential gas consumption was estimated at 4.9 quadrillion BTU (QBTU). The total residential gas consumption, which could occur if there were full gas utilization, is estimated at 6.75 QBTU.

- 10 million households currently are accessible to a gas main but are without gas—at 1,080 Therms per household, including heating and water heating, ultimately equals 1.1 QBTU.
- 6 million households currently with gas, but without gas heating equals 0.45 QBTU, at 750 Therms per household.
- 7.7 million households currently with gas, but without gas water heating, equals 0.23 QBTU, at approximately 300 Therms per household.
- 24 million households with gas but without gas cooking equals 0.07 QBTU, at approximately 30 Therms per household.[8]

If full conversion were obtained, this would provide an increase of 1.85 QBTU, a 38 percent increase in the overall level of residential gas consumption.[9] It should be noted, however, that any increase could only occur over an extended time period and that an increase of this magnitude in the near future does not appear likely.

[7] Ibid., Pg XI.

[8] Therm consumption for each appliance per household was based on an informal market survey conducted by the Demand and Distribution Task Group.

[9] Information obtained from Energy Information Administration, *Housing Characteristics 1990*, DOE/EIA-0314(90).

TABLE 2-5

POTENTIAL MARKET FOR U.S. RESIDENTIAL USE OF NATURAL GAS 1981 AND 1990 (Million Households)

Uses	1981	1990
Household Already Uses Natural Gas but Not as:		
Main Space-Heating Fuel	7.2	6.0
Main Water-Heating Fuel	7.8	7.7
Main Cooking Fuel	21.2	24.0
Household Does Not Use Natural Gas, but it is Available in the Neighborhood	9.9	10.0

The same household may be represented more than once depending on the number of uses it makes of natural gas.

The figures in this table for 1990 were derived from Table 19 of the *1990 Residential Energy Consumption Surveys (RECS)*. For example, the figure of 24.0 million for households that could use natural gas for cooking was derived by subtracting the 33.7 million households that use natural gas as their main cooking fuel from the 57.7 million households that use natural gas for some purpose.

SOURCE: Energy Information Administration, Office of Energy Markets and End Use, Forms EIA-457 A, B, and C of the 1981 and *1990 Residential Energy Consumption Surveys (RECS)*, Table 19 and RECS Public Use Data Files.

FACTORS THAT DRIVE RESIDENTIAL GAS DEMAND—OPPORTUNITIES

Table 2-4 presents data on some of the major factors that drive residential gas demand: population, housing stock, gas penetration, and price.

Penetration

Natural gas consumption has a major part of the single family market: 55 percent, varying by region. The penetration of natural gas appears in the long run to be a function of the relative cost of competing fuels. The natural gas industry is still recovering from the moratorium on new hook-ups during the 1970s. Having been out of the market for an extended period of time, the industry found that building practices, customer acceptance of competing fuels, and expectations had changed. It appears that natural gas is making a substantial comeback, particularly in the replacement market. Since the new construction industry has recently been slow, the replacement market becomes more significant.

Population

The demand for new housing is related to household formation and, ultimately, population growth. Some regions are growing, and population growth and relocations will have an effect on gas hook-ups. The mix of population is also important. For example, younger people, new families, singles, and other living groups different from the traditional four person household can have an impact on gas demand. These types of households tend to live in multi-family housing and in housing units with less space than is traditionally required. In some areas of the country this type of housing requirement may be more electric heat pump oriented than central system/gas furnace oriented. A challenge facing the gas industry is to tailor equipment to available markets while ensuring that the equipment is cost effective.

Alternative Piping

Alternative piping systems have recently gained attention as a means of increasing gas consumption. They offer greater flexibility in piping installations at a reduced cost, thereby removing one of the impediments to the installation of gas—the relatively high cost of piping. Both Corrugated Stainless Steel Tubing (CSST) and copper piping use smaller diameters that enable longer continuous runs with fewer fittings. This also allows for less inventory space and some sources have suggested a savings in labor of approximately 50 percent.

Environmental Issues

Environmental issues have become increasingly important in recent years. As a result, regulatory and legislative activities such as the Clean Air Act Amendments of 1990, have required customers to consider the environmental impacts of energy use. This may favor the increased penetration of natural gas. The increases could be a result of three basic factors: (1) an increase in the relative prices of alternatives to natural gas; (2) a direct prohibition on some pollutants; and (3) incorporation of environmental factors into utility planning processes.

Specific Pollutants

While there are a number of important categories of pollutants associated with energy use, the following five broad categories are the most important concerning competitive end-use markets:

- ***National Ambient Air Quality Standards (NAAQS) Pollutants:*** nitrogen oxides, carbon monoxide, sulfur oxides, inhalable particulates, and organic gases (total organic gases, volatile organic compounds, and methane).
- ***Global Climate Change Compounds:*** carbon dioxide, methane, tropospheric ozone, nitrous oxide, and halogenated compounds.
- ***Indoor Air Pollutants:*** nitrogen oxides, carbon monoxide, aldehydes, inhalable particulates, radon, and toxic chemicals.
- ***Halogenated Carbon Compounds:*** chlorofluorocarbons (CFCs), hydrogenated chlorofluorocarbons (HCFCs), hydrogenated fluorocarbons (HFCs), and halons.
- ***Hazardous Wastes:*** mercury and other hazardous metals, PCBs, and CFCs.

Pollutants that are directly prohibited as a result of the Clean Air Act Amendments of 1990 are CFCs. This Act calls for the phasing out of CFCs by the year 2000 and imposing excise taxes in the meantime. A recent Presidential Order is accelerating that date to 1995. Residential gas A/C is ammonia based, as opposed to electric A/C that is CFC or HCFC based.

In reference to space heating systems, carbon dioxide (CO2) is the primary "greenhouse gas" thought to contribute to global warming. Residential gas heating systems emit 33 percent less CO2 than oil. Also, sulfur dioxide and nitrous oxide emissions are much greater with electric or oil systems, contributing to acid rain and general air pollution.

Ideally, any analysis of the environmental benefits of gas versus competing options should look at environmental impacts considering all of the above. However, limited analyses that look at selected pollutants can provide useful information. Caution should be taken when making generalizations based on these limited analyses.

Selected Study Findings

The following studies indicate the inability to generalize the environmental benefits of one fuel source over another. They appear to be at odds, indicating that important issues appear to be controversial and still somewhat unresolved.

American Gas Association Study Findings

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 average fuel utilization efficiency [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 CO2 emissions attributable to a new, efficient natural gas space heating system in a 1,500 sq. ft. home are approximately 77 percent lower than that of an existing electric resistance heating system in the same size home, with electricity supplied by power plants (see Figure 2-5). The same is true for a house double the size, 3,000 sq. ft. (see Figure 2-6).
- Converting existing fuel oil systems to new natural gas space heating can reduce CO2 by about 47 percent.
- Converting an existing heat pump to new natural gas space heating can reduce CO2 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.

U.S. Department of Energy Study Findings

The U.S. DOE study, *Energy and Global Warming Impacts of CFC Alternative Technologies* (December 1991), compared the direct and indirect global warming contributions of gas-fired absorption air conditioners to electric-driven vapor compression technologies. The study concluded that "It is clear that this technology [gas-fired absorption A/C] results in a severe global warming penalty relative to HCFC-22 vapor compression systems regardless of electric generation fuel." The authors also concluded that while thermally activated heat pump technologies may have global warming benefits in the long-term, "it is unlikely that products using natural gas or other fossil fuels will have a significant impact in the time period corresponding to the CFC phaseout" required by the Clean Air Act.

New Equipment

There have been a number of advances in new residential gas equipment, as mentioned previously, in conjunction with the Appliance Efficiency Standards. Of particular note are higher efficiency boilers, furnaces, dryers, and ranges. The residential gas heat pump, while still in the testing stage, is expected to be a major player in the near future. In addition, new products that increase efficiency and ambiance for the consumer include gas fireplace logs, which offer modern convenience, the cleanest burning fuel, and old-fashioned charm. They provide the ambiance of a woodburning fireplace at half the cost of seasoned firewood, without the work, and without negative environmental impacts. In addition, they provide

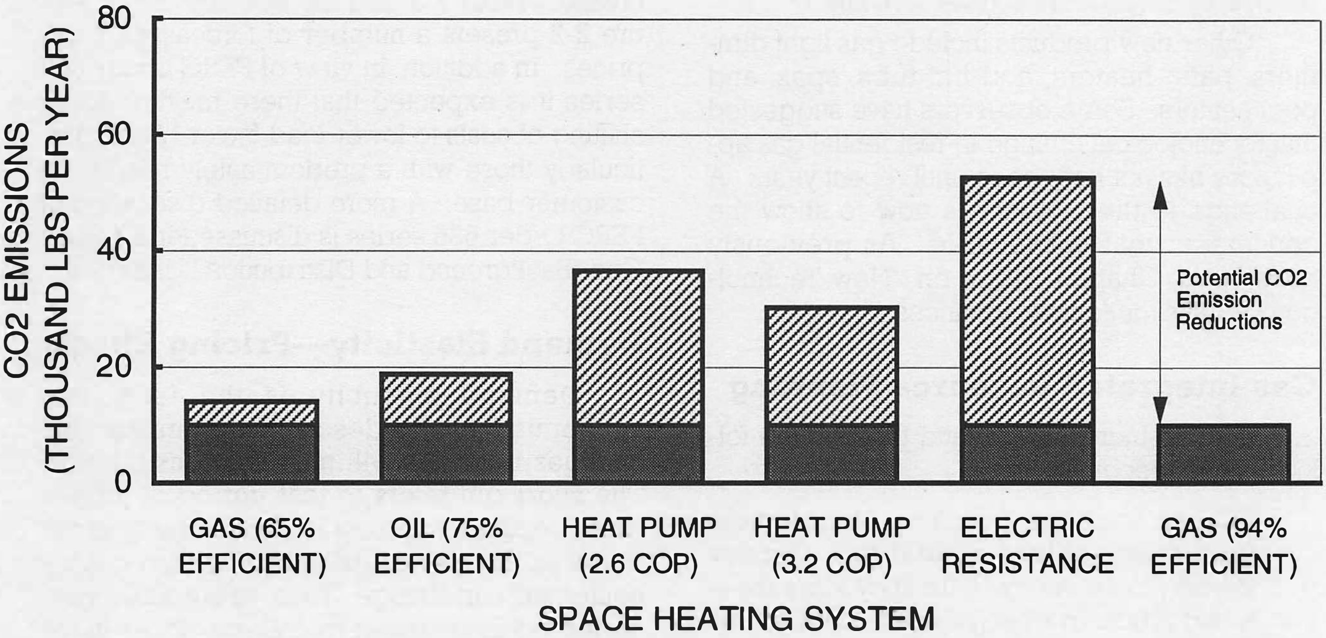


Figure 2-5. Annual Carbon Dioxide Emissions Attributable to Residential Space Heating Systems—1,500 Square Foot Home.

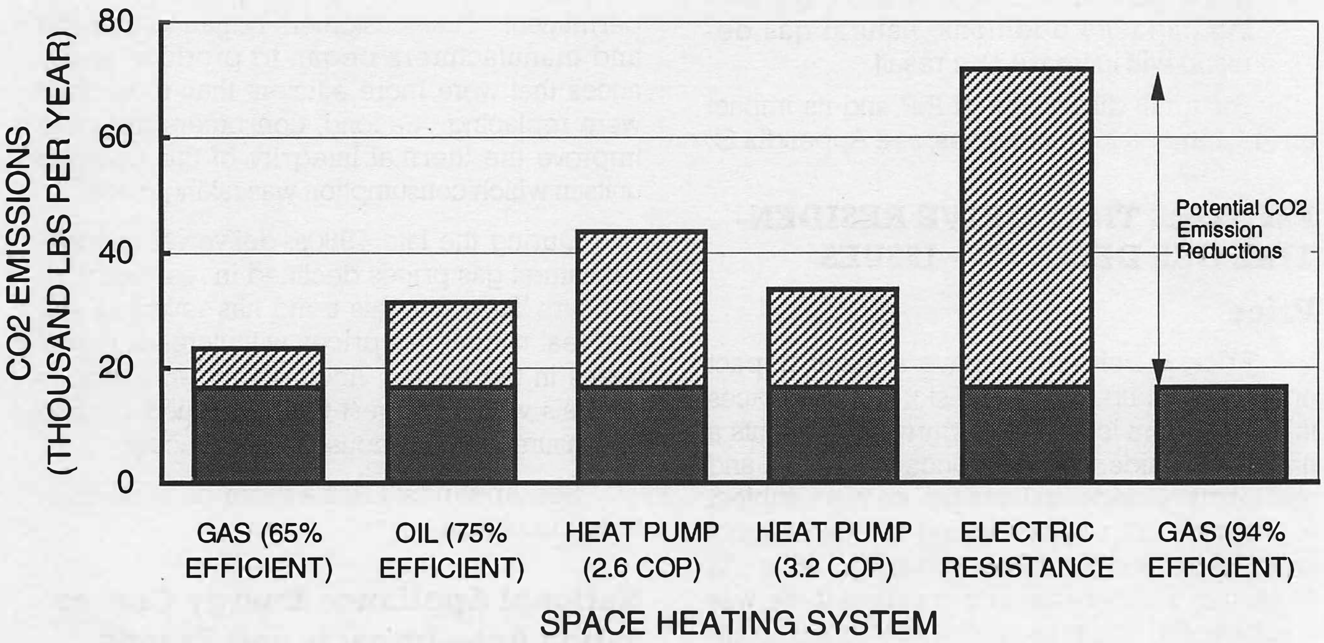


Figure 2-6. Annual Carbon Dioxide Emissions Attributable to Residential Space Heating Systems—3,000 Square Foot Home.

NOTES: Includes consideration of total energy consumption from point of purchase through end use. Homes are approximately 20 years old with construction and insulation typical of that period. Heating requirements based on moderate region (St. Louis).

SOURCE: American Gas Association, Planning and Analysis Issue Brief 1989-13, "Identification of Errors in Science Concepts, Inc., Greenhouse Paper," August 25, 1989.

value; according to *Remodeling Contractor* magazine, gas fireplace logs can return 138 percent on investment at time of resale.[10]

Other new products include gas light dimmers, patio heaters, and hot tubs, spas, and pool heaters. Some observers have suggested that technological change in residential gas appliances has not kept pace until recent years. A challenge to the industry is now to show the consumer what is available. As previously mentioned, Chapter Seven on "New Technology" details these new advances.

Gas Integrated Resource Planning

IRP can increase demand through the following two mechanisms:

1. IRP can favor the switching of customers from other fuels to natural gas, thereby leading to an *energy* efficiency increase—a reduction in energy used—but an increase in the use of natural gas.
2. IRP *can* lead to consumption increases. Therefore to the extent that electric utilities are fully engaged in IRP and natural gas is the fuel of choice for future generating capacity additions, natural gas demand will increase as a result.

For a full discussion of IRP and its impact on the demand for natural gas, see Appendix C.

FACTORS THAT DRIVE RESIDENTIAL GAS DEMAND—ISSUES

Price

Price is believed to have a major impact on gas consumption. The history of gas prices in recent years is mixed. Figure 2-3 presents a history of residential gas prices in nominal and real terms. Residential gas prices were subject to a significant run up during the gas supply shortages of the late 1970s and early 1980s. As a result of the increase in gas prices there was a substantial impetus to manufacturers to increase the efficiency of the available gas equipment. In recent years, natural gas prices have been decreasing in real terms. Many observers believe that this has caused some decrease in the rate of conservation.

[10] *The Right Choice—Natural Gas Fireplaces Equipment*; Consumer Information Committee of the American Gas Association; 1988.

For the future, residential natural gas prices on a delivered basis are expected to increase. Table 2-3 and the accompanying Figure 2-2 present a number of forecasts for gas prices. In addition, in view of FERC Order 636 series it is expected that there may be some shifting of costs to lower load factor LDCs, particularly those with a predominately residential customer base. A more detailed discussion of FERC Order 636 series is discussed in Chapter One (Background and Distribution Issues).

Demand Elasticity—Pricing Effects

Demand elasticity is the term that economists use to describe the impact that changes in prices will have on consumption. The short run refers to that period of time in which capital equipment is fixed. The long run refers to that period of time in which capital equipment can change. Thus, as consumers experienced increases in natural gas prices in the 1970s, the short run reaction was to consume less natural gas through behavioral changes (lower thermostats, etc.). However, a more important and fundamental change occurred as the price increases began to be perceived as permanent. First, customers began to demand and manufacturers began to produce appliances that were more efficient than those they were replacing. Second, consumers began to improve the thermal integrity of the dwelling units in which consumption was taking place.

During the late 1980s, delivered residential natural gas prices declined in real terms. It appears likely that this trend has reversed and that real natural gas prices will increase in real terms in the future. Accordingly, an elasticity analysis would suggest that continued decline in consumption per household will occur.

See Appendix E for a more detailed Elasticity discussion.

National Appliance Energy Conservation Act—Impacts and Trends

Declines in consumption per customer have also been effectively legislated by the United States Congress. Congress has passed the National Appliance Energy Conservation Act (NAECA). Phase 1 of this legislation established mandatory appliance efficiency standards for a number of appliances that use natural gas as well as those appliances whose efficiency determines the amount of gas burned in another appliance. Phase 2, which is expected to phase in around the year 2000, while similar in scope, may require minimum efficiencies of 80-90 plus percent.

Historical, current, and projected appliance efficiency standards for a number of appliances are summarized in Table 2-6.

The affected appliances include heating and air conditioning, water heaters, dishwashers, clothes washers, dryers, and ranges/ovens. Efficiency standards applied to dishwashers and clothes washers impact natural gas consumption by limiting hot water usage and therefore natural gas consumption in those instances in which hot water is provided with a natural gas appliance. The other standards reduce gas consumption directly through increased efficiencies in the end-use gas appliances.

To examine the impact of these standards on natural gas consumption, consider the natural gas furnace, which NAECA required to be manufactured at an efficiency level of 78 percent by 1992. Prior to these standards, the average efficiency of a natural gas furnace was approximately 67 percent. Thus, ignoring other influences, every furnace that is replaced will increase efficiency by approximately 11 percent given today's standards. Given the life expectancy of a furnace to be 25 years, the vast majority of gas-fired furnaces will be replaced by 2010. The standards will be even higher in the future, expected to reach 80-90 plus percent for a gas furnace in 2000.

There have been discussions pertaining to the possibility of electric air conditioning systems becoming obsolete and being totally replaced by the electric heat pump. This would lower heat pump costs, due to economies of scale, and would increase competition for the gas heating market.

Access to Gas Mains and Population Density

Cost Issues

Another significant concern associated with the penetration of natural gas is the physical distribution problem. Natural gas utilities incur significant costs in the distribution of their product. As the density of the population that gas mains are projected to serve increases, these costs can be spread over a larger base of

TABLE 2-6

NATIONAL APPLIANCE ENERGY CONSERVATION ACT EFFICIENCY REQUIREMENTS: PAST, PRESENT, AND FUTURE

Product	1965	1992	2000
Furnace	67% AFUE	78% AFUE	80+% AFUE
Boiler - Hot Water	67% AFUE	80% AFUE	82+% AFUE
Boiler - Steam	62% AFUE	75% AFUE	?
Water Heater Storage	49%	54%	56-62%
Water Heater Instantaneous	NA	E.F. = 0.62	
Dryer	Standing Pilot	No constant burning pilot	Auto-dry
Range	Standing Pilot	Those with electric supply cord must not have constant burning pilot	?
Swimming Pool Heater	75% Thermal Efficiency	78% Thermal Efficiency	80+% Thermal Efficiency

SOURCE: NAECA and Washington Gas Research & Utilization.

customers and a competitive viability can be maintained.

Access Issues

Homes that have access to gas mains but do not currently utilize gas are called "on-mains," due to the close proximity of a gas main. Many utilities actively pursue "on-main" customers via direct mail and creative financing programs. Recently, several private industry vendors have become active in locating these potential gas customers and are selling these databases to the utilities. These are key markets for gas utilities to target, due to the ease of running a gas service and the fact that by cost effectively adding new customers the LDC effectively decreases operating costs per customer and for all customers.

Because of the standard, one-quarter to one-half acre lots of a typical suburban subdivision, "main" access is not a problem for many natural gas distribution utilities that serve largely urban and suburban areas. However, there may be problems in serving larger lots depending on load and other factors. It is difficult to economically justify main extensions into less densely populated areas unless substantial commercial or other types of load are available.

Economic Test Criteria—LDCs

LDCs need to work within main extension policies in addressing the provision of service to new customers. Most LDCs have economic test criteria for the extension of facilities to serve new customers. These tests ensure that the utility attaches load that meets long run profitability criteria. This is especially relevant in the residential market where extensions to serve subdivisions may not be profitable in the short run, but facilities must be in place to provide service to the commercial enterprises that inevitably result from new residential growth and will be along that main extension. Historically, commercial establishments have a greater utilization of natural gas than do residential and, therefore, provide the necessary demand base to justify the main extension. In this scenario, if the LDC did not install its facilities to serve the new subdivision it would not be in place to pick up the commercial business.

An inflexible extension policy would have the LDC walk by the subdivision and, most likely, walk by the commercial business because the residential demand, by itself, might not have passed the economic criteria. In this instance, not only would the utility have passed up all this business but, most likely, would have lost it for the life cycle of the alternative heating equipment. This points out the necessity of maximizing gas utilization in premises by capturing more loads, thereby increasing the likelihood of passing an economic test and thus being able to serve that load.

While all extensions should meet an economic test, either in the short run or the long run, it must also be remembered that LDCs, like all companies, need to grow. Stated differently, absent growth, costs go up without an increase in new customers; therefore, rates go up.

Electric Heat Pump Trends

Prior to the moratorium on new gas connections during the 1970s, natural gas was the preferred fuel choice for space heating and water heating applications. This was primarily based on the fact that electric options were more expensive to operate. However, with the advent of the heat pump, a new alternative to natural gas and oil was available. The heat pump will present a significantly greater challenge to the preference of natural gas as a heating option. Also, in some areas, residential rehabs and remodeling result in the development of multi-use space in what was formerly single family space. This increased utilization of space is sometimes associated with the increased installations of heat pumps. Also, multi-use spaces generally involve renters, thus the owner is generally more concerned with the first cost of the equipment rather than the equipment operating costs. As a result, there is sometimes a conversion from gas.

Price Analysis of Gas & Electric

Another factor that calls into question the continued expansion of natural gas is the trend in the pricing of gas and competing fuels such as electricity. Any discussion of the relative economics of natural gas versus electricity is based on the relative prices of the fuels.

If prices are set below marginal cost, one could assume that consumption of gas or electricity is not at an economically efficient level and therefore leads to unnecessary consumption of the respective fuel source. Such rates are believed by some to be economically inefficient, and would lead to unnecessary consumption of one fuel relative to the other.

The important point of this discussion is that price is the only signal that the economy sends regarding which fuel should be consumed. If natural gas enjoys an advantage in this regard, it will be consumed. If electricity enjoys an advantage, its increased consumption will be favored. Comparative price analysis using appropriate marginal cost estimates can help determine which fuel source's prices may be set inefficiently and therefore provide unfair advantages.

Other Impediments to Increased Natural Gas Consumption

Impediments to natural gas consumption include concerns over first cost and operating cost factors. In general, natural gas equipment has a higher first cost than the major competing fuel; but the operating cost is lower, resulting in an overall lower life-cycle cost. In view of consumer discount rates, uncertainties and lack of information, and the split between owners and users in the case of multi-family space, this may present a problem to the increased consumption of natural gas in some residential markets.

CONCLUSIONS

Up to this point the pros and cons tending to increase or decrease natural gas consumption in the residential sector have been outlined. Clearly there are a number of driving factors at work:

- It is likely that consumption per household will continue to decline.
  - Energy efficiency and conservation will continue. As older equipment continues to be replaced with newer equipment, we will continue to see trends towards increased energy efficiency.
  - Integrated Resource Planning is likely to increase its impact on the residential market.
- The number of residences with natural gas service will continue to increase. The NPC and the gas industry believe that consumers will continue to prefer gas as a total energy source to electric based on comfort, value, environmental awareness, and price. In addition, there is a gradual tendency for conversions from other fuels to gas.
- The penetration of gas heating in the residential market is returning to historical levels as restrictions on gas system expansions have been removed.
- The impact of new technologies in the residential market will continue to improve the economic efficiency and penetration of gas appliances.

Accordingly, it is likely that consumption per household will continue to decline, while the number of households using gas continues to increase. This results in the projected level of overall residential consumption remaining fairly level. This does not mean that the residential marketplace is one in which there is little activity. LDCs have active marketing programs, which feature the advantages of all types of gas appliances (e.g., heating, water heating, cooking, drying, fireplaces, grills, and other options). At the same time, electric companies have active programs underway for the heat pump and other electric options. However, overall consumption of 4.6 QBTU per year is projected to remain relatively constant.

THE REGIONS

The regional reports are briefly summarized below. In most regions, very little additional consumption of residential gas is projected to occur, except in parts of Regions One, Two, and Three. Additional customers will be hooked up, and penetrations will increase, but substantial trends towards conservation will offset increased sales. Much of the heating conversion will come from oil (generally in significantly older homes) or electric (generally in homes built during the natural gas moratorium of the 1970s).

Region One: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont

The New England gas market has traditionally been characterized by a high percentage of sales to weather sensitive, firm customers who use gas primarily for heating purposes. As a result, the industry has experienced winter peaks that have greatly exceeded daily consumption. According to the State Energy Data System, total gas consumption in New England was 426.7 trillion BTU (TBTU) in 1990 compared to 303.9 TBTU in 1980. This was a 40 percent increase in natural gas consumption over this period.

The residential sector is the largest gas consuming sector in New England, accounting for 41.3 percent of total sales in 1990. Although residential consumption increased from 149.3 TBTU in 1980 to 176.2 TBTU in 1990, the residential share of regional natural gas consumption dropped from 49.1 percent in 1980 to 41.3 percent in 1990 due to growth in other sectors, particularly the electric generation sector.

Natural gas market share in the Region One residential sector is far lower than that in the rest of the United States. This is primarily because natural gas service is not yet available in many areas of New England and a significant proportion of the customers who have gas service do not utilize gas for space heating. The saturation of gas service and gas heat in New England continues to lag far behind the rest of the United States, despite the significant increase in the number of homes heating with gas in the past decade.

Over the past fifteen years, LDCs in New England have concentrated on increasing the penetration of gas heat in homes with gas service, and on increasing the saturation of gas service in households that are located on or near mains. Both of these programs have been relatively successful. For example, in 1975 only 55 percent of the households in New England which had gas service utilized natural gas for space heating; this figure has increased in nearly every year between 1975 and 1989 and has reached 71 percent in 1989. In comparison, the percentage penetration of gas heat in households with gas service in the rest of the United States has remained relatively constant over this period, increasing only slightly from the 85 percent level achieved in 1975 to 89 percent in 1989.

Region Two: New York and New Jersey

The residential conversion market is seen as the remaining major market with substantial growth potential in natural gas demand. As of 1990, the saturation of residential customers with natural gas service was 52 percent in New York and 70 percent in New Jersey. Obstacles to increasing market share were seen as long-term service contracts between residential customers and oil dealers, and ad campaigns by oil dealers. It was suggested that a target of 85 percent penetration would be appropriate.

Region Three: Delaware, Pennsylvania, Maryland, Virginia, West Virginia, and District of Columbia

Expected trends in gas share in the residential market include:

- In general, the gas market share of the residential market will continue to grow as a result of the cost of electricity increasing faster than the cost of gas due to the 1990 Clean Air Act Amendments compliance by electric utilities and as a result of new pipeline capacity being made available in areas where oil is prevalent.
- The number of new residential customers will continue to grow, both from new construction and conversions from other fuels.
- Gas consumption per residential unit will continue to decline.
- Total residential gas consumption will remain relatively flat or slightly increase.
- The perception that gas is the preferred fuel for the residential market will continue.
- As electric utilities take advantage of Demand Side Management opportunities, the add-on heat pump will become a stronger competitor for the residential space heating market.

Residential consumption is projected to remain relatively flat, or slightly increase. The number of new residential gas customers will continue to grow, both from new construction and conversions from other fuels. However, conservation will offset increasing market share and new customers.

Region Four: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee

Region Four on average has mild winters and hot summers. Therefore, air conditioning, rather than heating, is the more prominent residential energy use. This is part of the reason gas's residential market share is only about 2/3 the national average and why the electric heat pump will pose significant competition.

In homes built prior to 1974, gas heating has about 50 percent market share, electricity has 25 percent. For homes built from 1974 through 1987, 70 percent use electric heat and only about 14 percent gas. Since then, residential customer growth has outpaced household formation considerably, indicating that gas is now achieving a higher share of the heating market in new residences.

Over 90 percent of the homes with gas service are heated by gas. Only 75 percent of the homes with gas have gas water heaters. This provides a relatively significant growth opportunity since water heating is 50 percent of the load in parts of the region. Growth in numbers of residential customers will be offset by declines in consumption per customer; overall consumption may be flat or decline slightly depending primarily on the region's water heating programs.

The region is very supportive of the gas heat pump since the region's warm weather makes the electric heat pump a significant competitor.

Region Five: Illinois, Indiana, Michigan, Ohio, Wisconsin, and Minnesota

Residential consumption of natural gas is the highest in the country in this region. Approximately one-fourth of the nation's gas heated homes are in this region, as well as the largest stock of gas water heaters, ranges, and clothes dryers. Natural gas is expected to maintain a price advantage over other residential fuels for the foreseeable future.

Low population growth combined with increased appliance efficiencies are the forecasts predicted for the years 1990-2010. These trends will lead to the decrease in the region's residential energy demand. Heating appliance efficiencies and thermal integrities of homes are expected to increase, lowering the amount of energy required to heat buildings in the region. This predicted decline in heating load is the major reason for the expected decline in residential gas use. Despite these expected trends, natural gas's expected 63 percent share of the total energy market in 2010 remains over twice as large as the predicted electric usage.

Region Five has a long heating season and low gas prices, which allow gas furnaces to easily beat electric systems even though the electric systems are less expensive to install. Gas prices are expected to remain below distillate throughout the forecasted period, which will enable the gas systems to win in all cases. Gas-fired systems are expected to remain the space heating choice for the new housing units.

Region Six: Arkansas, Louisiana, Oklahoma, Texas, and New Mexico

Residential gas consumption accounts for just 8 percent of the region's total gas consumption. Historically, demand has been more or less stable, with mild fluctuations caused by changes in weather patterns. Residential gas consumption per customer has been declining, from 75 million BTU in 1985 to 66 million BTU in 1990. This drop is caused by variations in annual degree days, the pace of energy conservation, and gains in energy efficiency in household appliances.

Natural gas is the dominant fuel in space-heating applications. Gas competes with petroleum fuels in the residential space-heating market and with electricity in space-heating, water-heating, cooking, and clothes drying applications. Electricity is the primary alternative fuel to natural gas in the residential market.

A major growth opportunity for gas in the residential sector arises from the low life cycle costs of space-heating using natural gas relative to those of electric space-heating. More aggressive marketing by LDCs should also increase new gas-based installations. As a result, natural gas is expected to maintain its share of the residential space-heating market in the region, unless electric utilities heavily subsidize heat pumps in conjunction with IRP/DSM programs. Choice of gas as space-heating fuel greatly improves its chances of capturing the water heating and cooking applications as well.

Residential gas demand is projected to continue to grow slowly, at an annual average rate of 1 percent during the next decade. Energy efficiency improvements continue at a slower pace, and growth of residential housing is also slower.

Natural gas will post small gains in market share against electricity in single family dwellings, but will continue to lose out to electricity in multi-family dwellings.

Region Seven: Iowa, Kansas, Missouri, and Nebraska

Since 1981, residential gas demand in the region has fluctuated between 290 billion cubic feet and 354 billion cubic feet. The number of occupied housing units using natural gas as heating fuel has increased in Region Seven, the average gas consumption per household has fallen 11 percent since 1984, reflecting the gains in energy efficiency.

Increases in residential gas demand, in the future, will be primarily determined by the rate of growth in the space-heating needs of new single family homes. The number of gas-heated homes (both single- and multi-family) is expected to grow by one percent per year through 2000. Efficiency gains in both new and replacement equipment, as well as improvements in the thermal integrity of homes, will partly offset demand increases that would occur due to growth in the number of gas customers.

Natural gas competes with petroleum fuels in the residential space-heating market and with electricity in space-heating, water-heating, cooking, and clothes drying applications. While gas is the dominant fuel in space heating applications, currently used by approximately 97 percent of the region's residential customers, conversions from propane and oil will provide some limited opportunities for growth. Life-cycle costs of space heating using natural gas remain below those of electric. Surveys suggest that home buyers prefer gas heat, and builders should respond accordingly. More aggressive marketing by LDCs should also pay off in new installations. As a result, natural gas is expected to maintain its share of the residential space-heating market. Choice of gas as space-heating fuel greatly improves its chances of capturing the water-heating and cooking applications.

For the next decade, the region's residential gas demand is expected to rise at an average annual rate of 0.5 percent.

Region Eight: Colorado, Utah, Wyoming, Montana, North Dakota, and South Dakota

Natural gas is the dominant fuel in this region. Natural gas is the only real source for space heating and domestic water heating. The only remaining areas that natural gas can increase market share within the space heating and domestic water heating market segments is to penetrate small towns and individual customers in rural or remote areas of the states. These types of extensions do not produce returns to justify the investment.

Although additional penetration in the residential space heating and water heating markets are probably not significant in Region Eight, the underlying constraint that contributes to this loss of additional market share is service extension policies. Service extension policies vary from state to state in Region Eight. Some are more restrictive while others are rather lenient. The overriding issue is the ability for distribution companies to extend service to customers and communities that are in remote or rural areas. These extensions are generally not economically feasible unless state regulatory commissions allow the utility to subsidize the extension or to allow a surcharge to be applied to the customers' bills within the extension area to provide the economic incentive to extend service.

One segment of the market that natural gas continues to face competition is in the multi-family market. Due to building code restrictions and up front capital costs associated with natural gas appliances and installation, electricity is very competitive in multi-family construction. To maintain and increase gas consumption in this market segment, the gas industry must focus on installation techniques and on the development of technology and appliances that satisfy the specific requirements of this market.

Region Nine: California, Arizona, and Nevada

In terms of market share, natural gas's dominance of the regions' residential market has been deteriorating gradually since 1980 when gas provided about 71 percent of residential energy demand. On average, gas consumption has fallen a half percent annually between 1980 and 1990 while electricity increased at a rate of 3 percent per year. Despite gains made by electricity in the region's total energy consumption, natural gas continues to be the preferred energy source in the residential sector for space and water heating applications.

Increased emphasis on conservation measures and the passage of appliance efficiency and building shell standards have decreased the level of energy consumption by 13 percent since 1980. Natural gas dominates the single family market for space heating and water heating where gas is available. In Northern California, gas is less available, while the electric heat pump dominates in Phoenix and Las Vegas, due to a moratorium on new gas hookups in the late 1970s.

The multi-family market is difficult to penetrate due to the high installed cost of individual metering, plumbing, and venting. As a result heat pumps capture a significant share of the multi-family heating market.

In total, natural gas consumption in the residential sector is projected to grow at about 1 percent per year as penetration of the new construction market is offset by conservation within the existing residential market. Gas should maintain or increase its market share against the principal competition, electricity, for all four major end-use residential applications.

Region Ten: Idaho, Washington, and Oregon

Demand for electricity in the residential sector accounts for more than half of the sector's total energy demand. Almost 7 percent of the electrically heated homes in the country are located in this region.

Much of the high electricity demand in Region Ten is directly attributable to its low cost. Regional electricity prices are currently only 2.5 times greater than those of oil and gas, while the average at the U.S. level is over 4.0.

The low electricity price allows electric systems to compete in oil and natural gas's traditional residential stronghold, space heating. Despite strength of electricity in the region, natural gas demand is expected to increase slightly through 2010. The stock of natural gas heated homes is expected to grow over the forecast period as it wins most of the nonelectric heating share.

Chapter Three
Commercial Sector

Commercial gas consumption refers to gas consumed in commercial buildings, such as office buildings, stores, schools, assembly buildings, warehouses, hospitals, restaurants, laundries, hotels, etc. Table 3-1 summarizes commercial gas consumption, based on information obtained from the Energy Administration's *Commercial Buildings Energy Consumption and Expenditures 1989*.[1] Energy consumption by the commercial sector is space driven; the Standard Industrial Classification (SIC) code of the occupant of commercial space is frequently irrelevant in terms of determining energy use. Rather, the building type (restaurant, hospital, hotel, laundry) and utilization of the space—hours of operation, building temperatures and air changes, type of office or other equipment, type of heating, ventilating, and air conditioning (HVAC) system—are the primary drivers of commercial sector energy consumption. These drivers may vary by type of commercial activity, for example restaurant and hospital needs. There are a variety of commercial building types: office buildings, food service, lodging, mercantile, warehouse, etc. Gas consumption in older commercial buildings is typically for space conditioning provided by central boilers and furnaces for heating and hot water. Relatively little growth in this sector is expected from conventional space and water heating. The level of gas consumption in newer buildings tends to be much lower, and in many cases the space conditioning energy is provided by a different fuel. Other commercial sector uses include laundries, cooking in the restaurant sector, and other types of process related energy needs. As is the case with the residential sector, the commercial sector is subject to substantial conservation. Figure 3-1 depicts historical gas consumption on an actual and weather-normalized basis. Table 3-2 summarizes natural gas forecasts in terms of consumption and price for the commercial sector. Energy consumption as outlined is generally projected as slightly increasing. Figures 3-2 and 3-3 graphically depict commercial gas demand and price projections.

Relatively little growth in this sector is expected from conventional space and water heating; a reduced expansion of commercial space, coupled with continued conservation, should make this type of natural gas demand essentially flat. Also, due to the large lighting loads, computer equipment requirements, and presence of personnel, space heating requirements tend to be minimal. Similarly, there is not a large demand for water heating due to the nature of office building requirements. Thus, any projected growth in commercial demand will probably have to come from continued expansion of energy intensive commercial buildings such as restaurants, laundries, hotels, and hospitals, particularly due to their high demand for hot water and commercial gas cooling options, as well as the development of small scale cogeneration and fuel cells. Natural gas vehicles (NGVs) in the fleet market will also be

[1] Energy Information Administration, *Commercial Buildings Energy Consumption and Expenditures 1989*, DOE/EIA-0318(89).

TABLE 3-1

NET ENERGY CONSUMPTION IN COMMERCIAL BUILDINGS BY PRINCIPAL BUILDING ACTIVITY

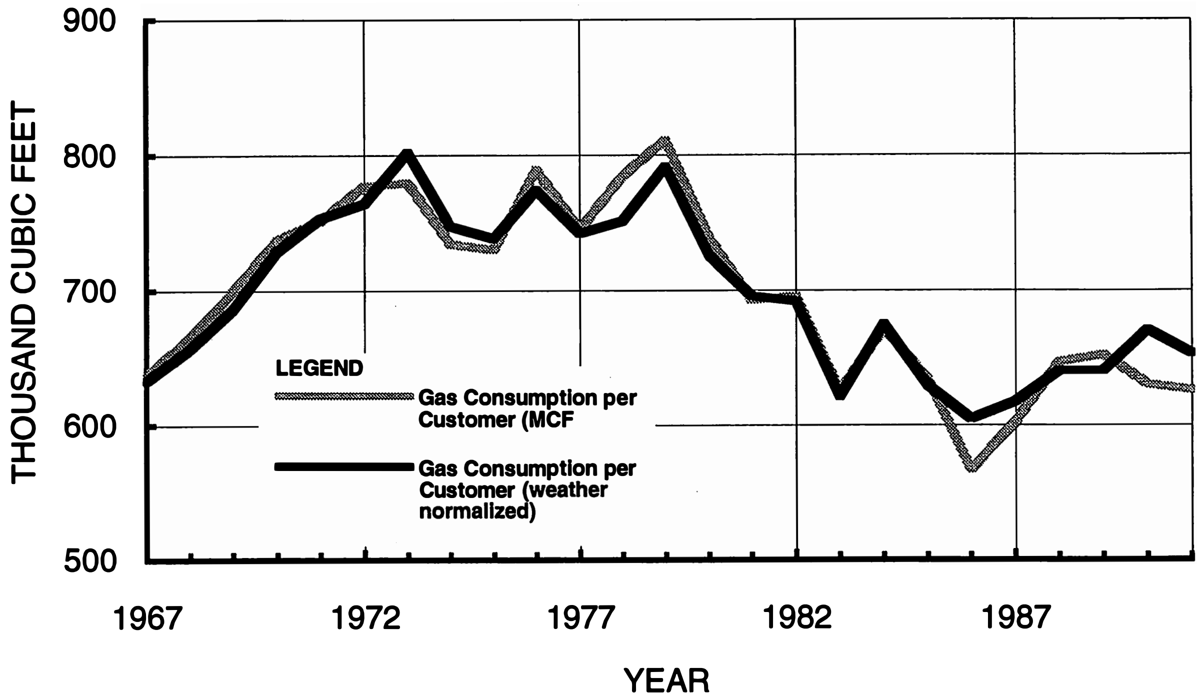
Principal Building Activity	Total net Energy Consumption (Trillion BTU)	Total Floorspace (Million sq.ft.)	Gross Energy Intensity (Thousand BTU/sq.ft.)	Gross Intensity per Hour of Operation (BTU/(sq. ft.*hr))	Consumption per Worker (Million BTU)
All Buildings	5,788	63,183	91.6	23.1	81.9
Assembly	441	6,909	63.8	19.6	109.7
Education	704	8,076	87.2	25.9	97.8
Food Sales	139	792	175.6	31.5	164.7
Food Service	255	1,167	218.4	41.7	131.2
Health Care	449	2,054	218.5	29.4	106.3
Laboratory*	293	919	319.2	79.0	198.7
Lodging	425	3,476	122.3	14.3	137.6
Mercantile and Service	1,048	12,365	84.8	22.4	84.4
Office	1,230	11,802	104.2	29.5	44.3
Parking Garage	42	983	42.6	7.1	126.1
Public Order and Safety	78	616	127.0	19.1	91.0
Warehouse	535	9,253	57.8	16.9	122.4
Other	50	610	82.7	16.3	79.4
Vacant†	98	4,161	23.5	11.0	66.5

Because of rounding, data may not sum to totals.

* In the Detailed Tables section, laboratory is included in the category of "other" buildings.

† Buildings in which more that 50 percent of the floorspace was vacant.

SOURCE: Energy Information Administration, Office of Energy Markets and End Use, Forms EIA-871A through F of the 1989 *Commercial Buildings Energy Consumption Survey*, Tables 11, 13, and B18.



SOURCES: AGA: American Gas Association, TERA Base Case 1992.
EIA: Energy Information Administration, *Annual Energy Outlook 1992.*
GRI: Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1992 Edition* (August 1991).
NPC: National Petroleum Council.

Figure 3-1. National Commercial Consumption per Customer.

TABLE 3-2

COMMERCIAL GAS DEMAND AND PRICE PROJECTIONS
(Quadrillion BTUs and 1990 Dollars per MCF, Delivered)

	1990		1995		2000		2010	
	Demand	Price	Demand	Price	Demand	Price	Demand	Price
AGA	2.62	$5.01	2.82	$4.75	3.17	$5.16	4.07	$6.01
EIA	2.62	$5.01	2.94	$5.33	3.05	$6.05	3.19	$8.06
GRI	2.62	$5.01	3.00	$4.98	3.30	$5.54	3.90	$6.90
Reference Case 1	2.62	$5.01	2.88	$4.88	2.96	$5.94	3.50	$6.17
Reference Case 2	2.62	$5.01	2.87	$4.52	2.87	$5.56	3.14	$5.92

SOURCES: AGA: American Gas Association, TERA Base Case 1992.
EIA: Energy Information Administration, *Annual Energy Outlook 1992.*
GRI: Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1992 Edition* (August 1991).
NPC: National Petroleum Council.

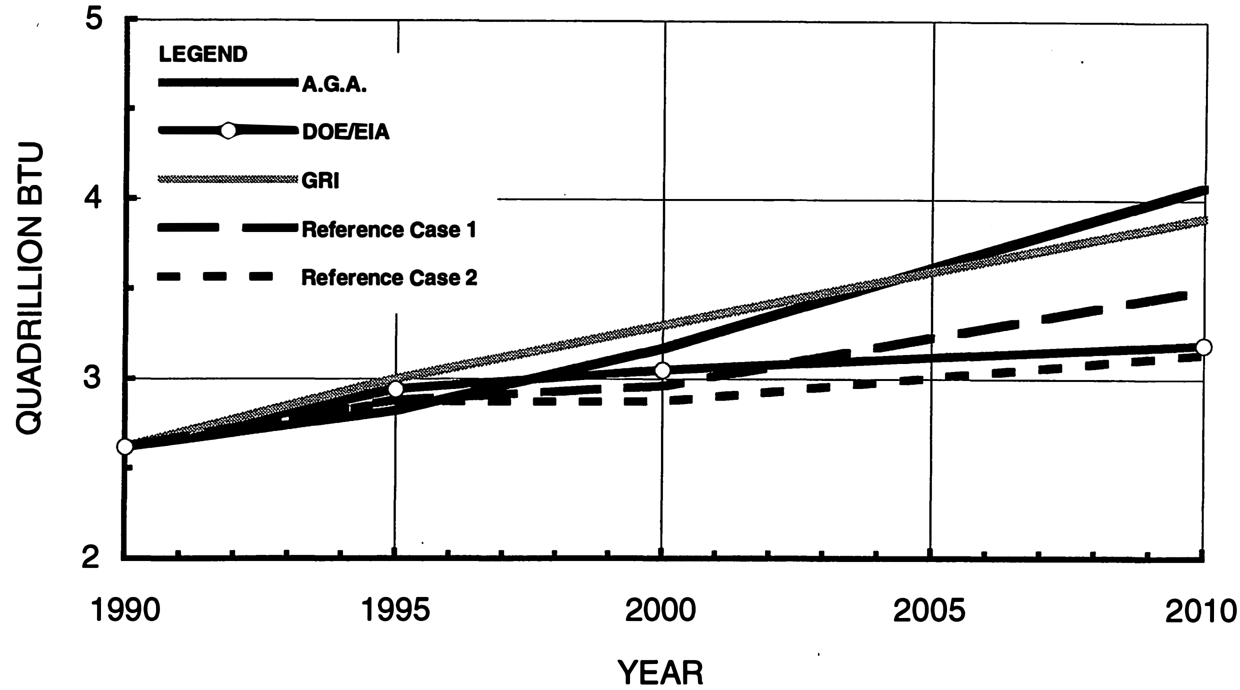


Figure 3-2. Commercial Gas Demand Projections.

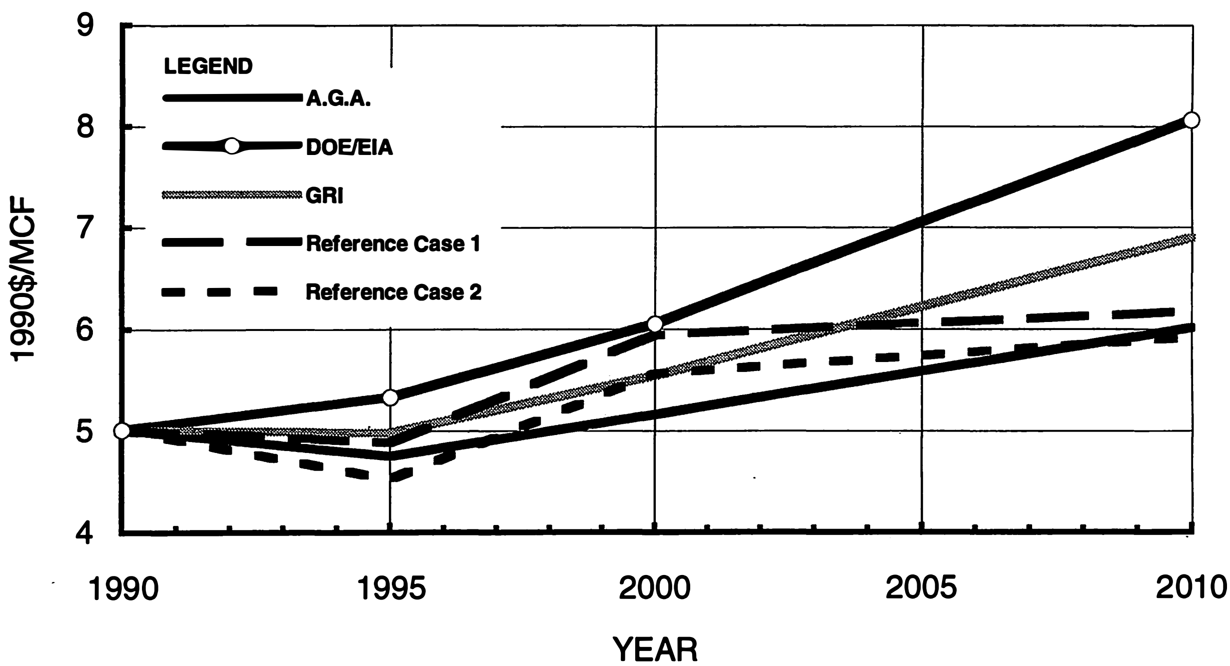


Figure 3-3. Commercial Gas Price Projections.

SOURCES:
- AGA: American Gas Association, TERA Base Case 1992.
- EIA: Energy Information Administration, *Annual Energy Outlook 1992.*
- GRI: Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1992 Edition (August 1991).*
- NPC: National Petroleum Council.

important; this issue is addressed in Chapter Six (Natural Gas Vehicles).

COMMERCIAL: AN OVERVIEW

Characteristics

According to the Department of Energy, there are 4.2 million commercial buildings in the United States, containing 58.2 billion square feet. On a total floor space basis, the largest percentage of the commercial building sector is comprised of Mercantile and Service facilities constituting nearly 13 billion square feet (22 percent), office buildings representing 9.5 billion square feet (16.4 percent), and non-refrigerated warehouses representing 8.5 billion square feet (14.6 percent). Assembly and education buildings each represent 7.3 billion square feet (12.6 percent).[2]

Cooling Usage

For space cooling, electricity has a 95 percent market share. Conversely, cooling with natural gas has only a 5 percent market share with 141,000 buildings being served with a total floor space of 2.9 billion square feet. Across the 1986 commercial buildings population as a whole, natural gas was used (primarily for heating) in 2.3 million buildings representing 55 percent of the buildings and 66 percent of the floor space.[3]

The primary cooling systems used in commercial buildings are as follows: 37 percent of cooled commercial buildings use central cooling systems; 31 percent are individual air conditioners; 24 percent use packaged air conditioning units; while 10 percent use air source heat pumps. Further analyses showed 75 percent of the buildings cooled utilize duct forced air distribution systems, while only 11 percent use fan coiled units.[4]

Any increase in commercial sector demand growth is projected to come from commercial gas air conditioning or increased market share. Nationally, natural gas has a 36 percent share of overall commercial energy use, as shown in Figure 3-4. Significant developments, such as the possible full scale commercialization of commercial gas air conditioning, or significant use of fuel cells are the only areas where gas demand can achieve major growth potential. See Appendix G for detailed information on commercial gas cooling technology.

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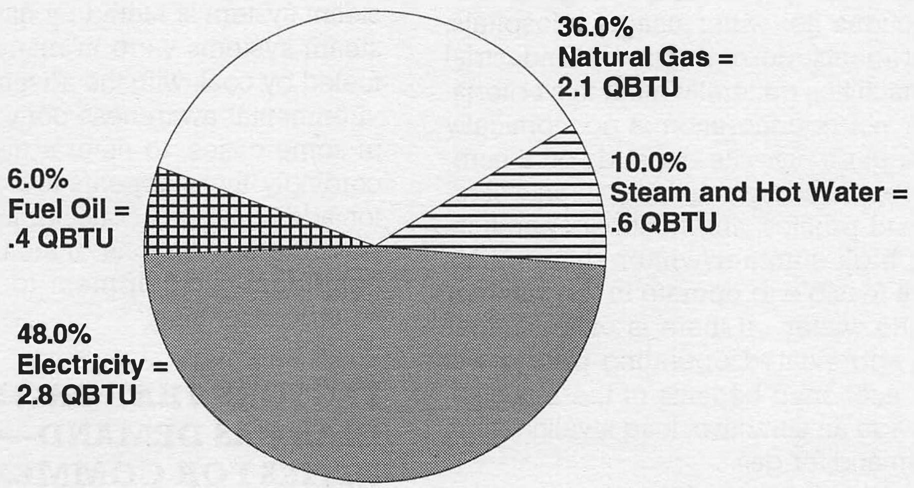
2 American Gas Association; Policy & Analysis Issues, Issue Brief 1991-5, "Advances of Natural Gas Cooling in the Commercial Sector: Equipment, Economics & Environment," Feb. 26, 1991.

3 Ibid.

4 Ibid.



SOURCE: Energy Information Administration, Office of Energy Markets and End Use, Forms EIA-871A through F of the 1989 Commercial Buildings Energy Consumption Survey, Table 11.

Figure 3-4. Net Energy Consumption in the Commercial Sector by Major Energy Sources, 1989.

Gas Heating Obstacles

The use of central systems with boilers in new high rise office buildings is becoming rare since space heating requirements in these buildings are minimal due to the large lighting and computer equipment needs. This, coupled with the presence of employees, actually results in cooling requirements even in the winter months. Domestic hot water requirements are also quite low. As mentioned, size is a key factor here; there is, however, limited potential for space heating in smaller buildings.

First cost for installing boilers, piping, and flue stacks is considerably higher for gas heating than installing direct electric heaters; therefore, architects and engineers, as well as property/building owners, tend to choose the electric systems. An increase in gas demand in high rise office buildings in the future will revolve around penetration of new, high efficient, double effect gas absorption air conditioning installations.

Commercial Cogeneration

Small-scale commercial cogeneration systems (and eventually fuel-cells) are another option that can, under certain circumstances, help a commercial building reduce its electric demand and associated costs, resulting in increased gas demand. In order for a commercial building to have cogeneration, the building does need to be of a type that has a significant usage of hot water and either a storage tank or fairly continuous hot water usage. Hospitals, hotels, apartments, dormitories, and industrial or process facilities generally meet this criteria. Whether or not cogeneration is economically feasible at a particular site depends on a number of factors including relative gas and electric rates, load profiles, and hours of operation. Areas with high summer/winter differentials may make it feasible to operate in the summer but not in the winter. If there is only summer usage, the abbreviated operating period will reduce the economic benefits of the machine, but will provide an attractive, load leveling, high summer demand for gas.

High Rise versus Low Rise Market

Until the mid 1960s, office buildings and other types of high rise space were typically heated with central boilers, fired with oil or natural gas. The fragmentation of commercial space among multiple tenants in high rises, coupled with rising energy prices and the desire to assign cost responsibility to end users, has resulted in floor specific HVAC and heating systems in many cases. The technology for floor-by-floor HVAC systems has been largely electric. With the demise of high rise central systems, the use of gas fired boilers generally went out of style. Accordingly, natural gas is used fairly infrequently for heating in buildings in excess of five stories, due to HVAC system selection and end-use load. In many high rise buildings, natural gas has been largely limited to the first few floors, for restaurant and similar uses.

In contrast, natural gas appears to have a major share of the low rise business, i.e., restaurants, laundries, hospitals, warehouses, etc. These types of buildings have definite hot water, cooking, heating, and other needs. The HVAC systems associated with gas consumption are appropriate and suitable. Figure 3-4, from an EIA report, shows that some fuel oil is still used in commercial buildings, probably in older central boilers; this 6 percent of the commercial load would be a potential for conversion. In addition, steam accounts for 10 percent of commercial consumption. In a few cities there is a district heating, central steam system providing energy to buildings. Although one could assume that such energy consumption would be a possibility for conversion, it appears that in many cases the central steam system is fueled by natural gas. Central steam systems were in many cases originally fueled by coal; with the advent of increased environmental awareness conversions to oil and in some cases, to natural gas occurred. Accordingly, there appears to be limited potential for additional gas consumption except for the possible installations of steam absorption air conditioning equipment to replace existing electric machines.

FACTORS THAT DRIVE COMMERCIAL GAS DEMAND—OPPORTUNITIES FOR COMMERCIAL GAS AIR CONDITIONING

Historical Cooling Characteristics

Total installed commercial air conditioning in the U.S. is approximately 116 million tons. As mentioned earlier, natural gas currently serves approximately 5 percent of this commercial air conditioning market. This computes to nearly 6 million tons of gas air conditioning, believed to be largely single effect air conditioning. It is estimated that over 5 million tons of commercial air conditioning is added or replaced every year. As an example of gas consumption, a 500 ton gas absorption cooling unit consumes approximately 12,000 thousand cubic feet (MCF) per year in the South and Southwest and 9,000 MCF per year in other regions. A 150 ton gas-engine chiller consumes approximately 2,600 MCF per year in the South and 1,900 MCF per year in other regions.[5] Figure 3-5 shows 1990 air conditioning installations by type of building structure. Central systems are usually used in hospitals, schools, and other facilities. Office buildings frequently use floor-by-floor units.

Tables 3-3, 3-4, 3-5, and 3-6 present information on 1989 and 1990 commercial gas cooling installations.

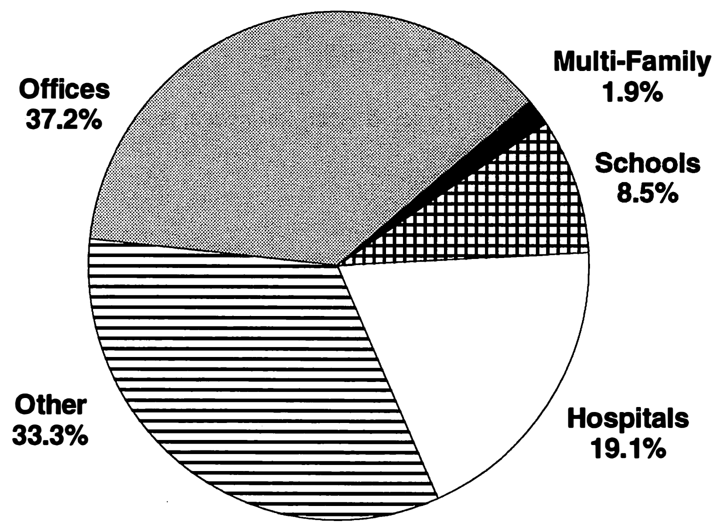
Future Opportunities—Gas Absorption Systems

The major opportunity for additional gas consumption in the commercial sector appears to be in commercial gas air conditioning. The development of double effect absorption equipment provides an opportunity for increased gas penetration of the commercial air conditioning market. Commercial gas air conditioning is still in the product introduction phase. First cost of the equipment is significantly higher than for the comparable electric equipment on a per ton basis. Installation cost is also significantly higher. However, in many regions gas absorption air conditioning does enjoy an overall life-cycle cost advantage, and increased penetration of gas cooling equipment is expected.

Benefits versus Costs

In spite of the higher first costs of the equipment and installation, commercial gas air conditioning is competitive in a number of locations on a life-cycle cost basis. It is expected that both types of costs should decline significantly as the equipment is introduced to the market. In addition, there may be substantial benefits to the electric utility in the substitution of gas air conditioning capacity for electric air conditioning capacity. At this time a number of combination gas/electric companies are offering cash incentives for gas air conditioning; this helps to keep overall costs down. The substitution of gas A/C for electric should be pursued

[5] Ibid.



SOURCE: American Gas Association, *Planning & Analysis Issues,* Issue Brief 1991-16, "1990 Commercial Gas Cooling Survey," Oct. 1991.

Figure 3-5. Air Conditioning Installations by Type of Building Structure.

TABLE 3-3

INSTALLATIONS OF COMMERCIAL GAS COOLING, 1989 & 1990 BY CENSUS DIVISION*

	1990			1989		
Census Division†	**Newly Installed Tonnage**	**Install-ations**	**Average Tonnage per Install-ation**	**Newly Installed Tonnage**	**Install-ations**	**Average Tonnage per Install-ation**
New England	3,816	36	106	3,995	43	93
Middle Atlantic	5,650	17	332	5,559	14	397
South Atlantic	1,075	21	51	470	15	31
East North Central	14,013	44	318	4,597	28	164
West North Central	6,780	6	1,130	1,250	1	1,250
East South Central	30	1	30	0	0	0
West South Central	330	2	165	1,670	3	557
Mountain	100	1	100	815	4	204
Pacific	8,539	27	316	3,285	28	117
U.S. Total	**40,333**	**155**	**260**	**21,641**	**136**	**159**

* Census division breakouts do not correspond exactly to the NPC Regional Task Groups. Since we are comparing trends, inconsistencies in conclusions should not appear. See Appendix F for a comparison.

† Some division averages reflect only limited installations.

SOURCE: American Gas Association, *Policy & Analysis Issues*, Issue Brief 1991-16, "1990 Commercial Cooling Survey," Oct. 28, 1991.

by local distribution companies as an attractive integrated resource planning (IRP) option. See Appendix C for further discussion of IRP.

Equipment Paybacks and Incentives

Tables 3-7, 3-8, and 3-9 present information on equipment costs and performance, and equipment paybacks. The payback for the incremental cost of gas equipment nationally averages in excess of three years. Building developers/owners/operators typically have a high discount rate. To many, a three year payback may be too long (though some distribution companies report that for reasons beyond straight economics, paybacks as long as five years are acceptable to some customers). When the payback exceeds an acceptable level, it then behooves the distribution company to offer equipment and rate incentives to encourage the installation of gas equipment. It is expected that increased use of gas cooling equipment will over time result in a decrease in

TABLE 3-4

1990 INSTALLATIONS BY EQUIPMENT TYPE

Equipment Type	Average COP*	Total Newly Installed Cooling Tonnage	Number of New Instal-lations	Percent of Total New Tonnage
Direct-fired †	1.0	14,260	87	35.4
Steam-fired †	0.9	8,895	8	22.5
Absorption‡	0.7	10,968	25	27.2
Engine Driven	1.4	2,790	20	6.9
Desiccant	1.0	175	5	0.4
Other	1.1	3,245	10	8.0
Total		**40,333**	**155**	**100.0**

* Coefficient of performance.

† Separate breakout of absorption systems (particularly double-effect systems).

‡ Absorption systems not classified as direct-fired or steam-fired equipment (particularly single-effect systems).

SOURCE: American Gas Association, *Policy & Analysis Issues*, Issue Brief 1991-16, "1990 Commercial Cooling Survey," Oct. 28, 1991.

TABLE 3-5

REPLACEMENT INSTALLATIONS FOR 1990 & 1989

	1990			1989		
	Tonnage	Instal-lations	Percent of Total Tonnage	Tonnage	Instal-lations	Percent of Total Tonnage
From Electric Systems	6,314	47	43%	3,705	33	68
From Gas Systems	8,462	31	57%	1,752	37	32
Total	**14,776**	**78**	**100%**	**5,457**	**70**	**100**

SOURCE: American Gas Association, *Policy & Analysis Issues*, Issue Brief 1991-16, "1990 Commercial Cooling Survey," Oct. 28, 1991.

TABLE 3-6

SYSTEMS REPLACED IN 1990

System Replaced	Replacement Tonnage	Replacement Installations
Centrifugal	5,114	35
Reciprocating	925	14
Direct-fired	142	24
Steam-fired	5,945	7
Waste Heat	0	0
Thermal Storage	0	0
Other	320	10
Total	**8,207**	**65**

SOURCE: American Gas Association, *Policy & Analysis Issues*, Issue Brief 1991-16, "1990 Commercial Cooling Survey," Oct. 28, 1991.

cost of this equipment, eliminating the need for such subsidies.

Future Outlook

It is difficult to project how much additional gas air conditioning can be installed on a yearly basis, but penetration will continue to improve as there is the achievement of economies of scale and market acceptance. Market acceptance may come about for a number of reasons:

- First costs of purchase and installation are coming down.
- As part of IRP efforts some utilities are considering gas equipment as an alternative to electric equipment. This permits the achievement of economies due to the decreased need for new electric generating capacity.
- Gas cooling is perceived to be environmentally acceptable: desiccant dehumidification, for example, does not use CFCs. Gas engine driven chillers do use CFCs, the same type used by new electric chillers.
- Restrictions on CFCs.

Environmental Issues

Commercial gas air conditioning is going through a resurgence of interest due to a variety of environmental and economic factors. For example, the 1990 Clean Air Act Amendments includes the following regulations:

- Over the next two years, a phase-out of CFCs will occur. Two U.S. air conditioning manufacturers will not ship any chillers using R-11 after January 1993.
- Dupont—the largest manufacturer of CFCs—will stop producing R-11 and R-12 in 1994.
- The manufacture of CFCs will be banned by 1995.
- HCFCs, which have only 2-5% of the ozone depleting potential of CFC-11 and 12, will be phased out by 2020.

Non-CFC refrigerants are being developed, but their use in existing chillers may require some modification to existing systems. Also, manufacturers have developed new chillers that can use either CFC or non-CFC refrigerants. Gas cooling equipment such as those using water as the refrigerant in a lithium bromide solution, also provides building owners with non-CFC alternatives.

The new double-effect gas chillers have become commonplace because they are twice as efficient as the single-effect version. Although they are more expensive than their electric counterparts, double-effect gas chillers' operating costs are considerably less than an electric machine, particularly in areas with high electric demand charges. The significant demand savings on the electric bill have also meant that rebates under LCP/DSM programs have brought the first cost more in line with electric machines.

In terms of the clean air issue, natural gas may or may not have advantages over its electric counterparts. Depending on electric utility fuel mix and marginal fuel, gas at 80 plus percent efficiency may produce less pollution than its electric counterparts. There is however a downside of gas equipment in that what little air pollution that is produced occurs at the site, whereas the electric pollution occurs at a generating plant that may be miles outside of an urban area and thus may have little direct effect

TABLE 3-7

ESTIMATED PERFORMANCE AND EQUIPMENT COSTS

Equipment Type	COP*	Equipment Cost†
Absorption Chillers (double-effect)		
	0.95	$900-$1,300/ton - 20-50 tons
	1.0	$720-$1,000/ton - 60-100 tons
	1.0	$375-$700/ton - 100-300 tons
	1.0‡	$400-$500/ton - 300-500 tons
	1.0‡	$350-$400/ton - 1,000-1,500 tons
D/X Roof Top		
	0.77	$1,170/ton - 15 tons
	N/A	$780/ton - 25 tons
Gas Engine-Driven Chillers		
	1.5	$500-$600/ton - 150 tons
with heat recovery	1.9	$600-$800/ton - 150 tons
	1.9	$450-$600/ton - 230-460 tons
	1.4	$800-$850/ton - 30 tons
	1.4	$530-$560/ton - 300 tons
with heat recovery	1.8	$560-$660/ton - 300 tons
Desiccant/Dehumidifier		
	1.5	$700-$1,300/ton - 40 tons
	0.7	$900-$1,100/ton - 60-80 tons

* COP = Coefficient of performance at full load. Part-load efficiencies for certain equipment can range up to 20 percent higher.

† End-user cost; installation cost estimates are 20% to 100% of equipment cost.

‡ Based on the higher heating value (HHV) of the fuel.

SOURCE: American Gas Association Survey of 10 gas cooling equipment manufacturers, February 1991.

on the air quality of the area they serve. As such, although gas equipment may be better from a global environmental perspective, electric equipment is sometimes preferred (i.e. gas-fired equipment restricted) in urban areas where they are not in attainment of established air quality standards.

CONCLUSIONS

Increased gas demand in the commercial sector is likely from increased penetration of gas air conditioning and the installation of cogeneration or fuel cell systems. No major change in commercial sector gas consumption

TABLE 3-8

ELECTRIC COOLING EQUIPMENT COST

Electric Cooling Equipment Type	Cost Range ($/ton)
High Efficiency Packaged Unit (up to 100 tons)	$475 to $775/ton
High Efficiency Air Source Heat Pump	
1 to 3 tons	$880 to $950/ton
5 to 30 tons	$500 to $725/ton
High Efficiency Water Source Heat Pump (up to 20 tons)	$275 to $525/ton
Air Cooled Reciprocating Chiller	
20 to 40 tons	$325 to $525/ton
50 to 75 tons	$325 to $400/ton
100 to 150 tons	$275 to $375/ton
150 to 200 tons	$225 to $350/ton
Water Cooled Reciprocating Chiller	
5 to 50 tons	$375 to $575/ton
75 to 150 tons	$225 to $375/ton
150 to 300 tons	$200 to $325/ton
Average Efficiency Centrifugal Chiller	
70 to 100 tons	$475 to $565/ton
150 to 300 tons	$250 to $300/ton
300 to 900 tons	$150 to $250/ton
900 to 1000 tons	$125 to $225/ton
High Efficiency New Centrifugal Chiller w/V8D	
300 to 900 tons	$175 to $275/ton

SOURCE: Edison Electric Institute.

is foreseen from traditional commercial gas use applications (space and water heating). Natural gas has a major challenge in penetrating the high rise market; there does not appear to be any major solution on the horizon in the short run. However, natural gas has a major share of the low rise market; some improvement is possible—as is the case in the residential sector. In some cases, natural gas increases its market share by substituting for No. 2 or No. 6 oil in office buildings. Natural gas also has some opportunities in the NGV market, specifically with fleets (see Chapter Six for further discussion of NGVs).

There have been major advances in new gas chillers, but the equipment is still in the product introduction stage. Increased marketing efforts and the use of incentives is needed

TABLE 3-9

GAS EQUIPMENT PAYBACKS*

	Atlanta	Chicago	Phoenix
Absorption Chiller (300,000 sq. ft. office building)			
Tonnage†	400	600	200
Incremental cost ($/ton)	227	185	245
Payback (years)	5.4	4.0	5.4
Desiccant Dehumidification (50,000 sq. ft. supermarket)			
Tonnage‡	30	§	30
Incremental cost ($/ton)	670	§	670
Payback (years)	0.8	§	1.4
Engine-Driven Chiller (50,000 sq. ft. office building)			
Tonnage¶	150	150	150
Incremental cost ($/ton)	330	330	330
Payback (years)	3.2	3.9	2.9

* When rebates offered to purchasers of gas equipment of $100/ton are included, paybacks drop by as much as 1.2 years.

† Hybrid systems with 29 percent gas in Phoenix, 62 percent gas in Atlanta, and 100 percent gas in Chicago. No credit for heating mode.

‡ Compared to an electric reciprocating system.

§ The paybacks take credit for reducing air flow by 50 percent. This is not possible in a city like Chicago due to code restrictions. Thus, about 70 percent of the savings attributable to the system, which come about as the result of reduced fan horsepower, are not available in Chicago. This also means that the Chicago supermarket cannot take credit for reduced first cost with regard to smaller duct work. Simple payback in Chicago is over five years. Generally, gas desiccant system economics are site- and code-specific.

¶ Compared to an electric centrifugal system.

SOURCE: American Gas Association Survey of 10 gas cooling equipment manufacturers, February 1991.

to spur market penetration. In the case of cogeneration, the commercial sector has seen the introduction of some packaged cogeneration, generally in the neighborhood of 30-150 kilowatts of capacity per installation. The small scale cogeneration market is likely to grow rapidly as new equipment (e.g., small turbines and fuel cells) are introduced and accepted by the market. Eventually, small scale cogeneration will have broad applicability throughout the commercial sector. Today, schools and hospitals have applied this technology on a significant scale. The equipment is generally of interest to commercial buildings with a large hot water need, e.g. apartments or hospitals. Fuel cells, the next generation of cogeneration systems, are just beginning their commercialization phase.

Their high efficiency and environmentally benign attributes could make them an attractive application in the commercial market.

THE REGIONS

The regional reports are briefly summarized below. In general, a slight increase in commercial gas consumption is projected. Due to substantial conservation efforts and efficiency improvements (e.g. double-effect versus single-effect cooling equipment) the projected increase is minimal.

The areas of increase vary by region, but overall environmental (1990 Clean Air Act Amendments) impacts will be favorable toward increased gas consumption. Relatively little growth is anticipated from conventional space or water heating. The growth sectors are in the areas of Natural Gas Vehicles and Gas Cooling. Cogeneration is also an area of increasing importance. Gas IRP programs will also work towards increased commercial consumption.

Region One: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont

As in the residential sector, commercial sector use in New England is also primarily firm year-round load, with roughly 85 percent of all commercial sector consumption on a firm basis. Commercial consumption increased from 87.7 trillion BTU in 1990 to 95.3 trillion BTU in 1990, and accounted for 22.3 percent of total regional natural gas consumption in 1990. Within the commercial sector, the major users of gas include Real Estate (apartments), Restaurants, Retail Trade, Health Services and Hospitals, and Schools. Interestingly, only Health Services and Hospitals consumed more gas on an interruptible basis than on a firm basis in 1988.

According to the Energy Information Administration's *State Energy Data Report Consumption Estimates 1960-1990*, of the 95.3 trillion BTU of energy consumed by the commercial sector in 1990, 25.5 percent was produced by natural gas, 35.9 percent by electricity, 20.7 percent by distillate oil, 15.3 percent by residual oil, 2.2 percent by other petroleum, and 0.5 percent by coal. While average growth in total commercial consumption in Region One was 1.7 percent per year from 1980 to 1990, average annual growth in natural gas use was only 0.8 percent. Therefore, over the past decade, the market share of natural gas in New England's commercial sector has declined while the market shares of electricity, residual oil, and other petroleum have increased.

In comparison, 1990 U.S. commercial sector energy consumption was almost equally represented by natural gas and electricity, with 41.6 percent and 43.2 percent of the fuel mix, respectively. Additionally, distillate and residual oil combined accounted for only 11.0 percent of U.S. commercial consumption compared with 36.0 percent in Region One. The growth rates in usage of each fuel over the past decade was fairly similar to that of New England, although residual oil consumption declined at an average annual rate of 8.1 percent in the United States compared with an average annual increase of 1.9 percent in New England.

With only 25.5 percent of commercial sector consumption, natural gas could potentially increase its market share to a level similar to the United States as a whole. New natural gas technologies aimed specifically at the commercial sector may aid in achieving some of this potential over the next decade. Natural gas-fired air conditioners, especially for large commercial applications, are well developed at the present time. The major constraints to achieving market potential for gas cooling technologies are high initial costs and lack of funds for market introduction. The natural gas-powered fuel cell is another technology with potential applications in the commercial sector since the ideal market for fuel cells are cogeneration candidates that have large continuous electric and thermal loads. These candidates include hospitals, nursing homes, and computer intensive commercial properties.

Region Two: New York and New Jersey

The average annual growth rate for natural gas in the commercial sector, for 1990-2010, is estimated at 2.18 percent. The commercial sector market share increased from 22 percent to 40 percent in the past 2 decades. This seems to be due mainly to the dramatic decrease in the use of residual and distillate oil and other petroleum products from nearly 60 percent to 25 percent. Natural gas has gained market share in the commercial sector by a substantial portion, even greater than the gain in the residential sector. It is expected that recent environmental mandates will contribute to a continuing market share increase.

Region Three: Delaware, Pennsylvania, Maryland, Virginia, West Virginia, and District of Columbia

Expected trends in gas share in the commercial market include:

- Region Three expects the gas portion of the commercial sector to continue to grow as the costs of electricity increase due to Clean Air Act compliance.
- Gas consumption per commercial unit is expected to decline, but total commercial consumption is projected to increase on a slight to moderate basis.
- As electric utilities take advantage of Demand Side Management opportunities, the add-on heat pump will become a stronger competitor for the commercial space heating market.
- Commercial office space continues to be designed with high lighting levels.

Opportunities exist in the areas of space heating, water heating, air conditioning, power generation, and compressed natural gas vehicles. Constraints to taking advantage of these opportunities include National Appliance Energy Conservation Act (NAECA) pressure to develop new equipment, resulting in fewer competitive pieces; regulatory lag time between investment and rate base realization; restrictive building codes and slow acceptance of new technologies; lack of rate recovery of marketing expenses; and pipeline capacity and restrictive government regulations for expanding capacity.

Region Four: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee

Commercial energy use is influenced primarily by weather and demographics. Over the past ten years, the gross state product contribution of the commercial sectors grew two to three times faster than the population. Highest growth was in wholesale trade, with services a close second. Though the gas customer base has grown considerably, conservation has offset this customer growth up until the past five years.

Overall, commercial gas consumption growth is expected to be modest because of continued conservation. However, gas cooling holds a great deal of potential for load growth, particularly in the southernmost areas of the region. As a result, distribution companies have established gas cooling departments and have greatly enhanced their level of expertise over the past few years. Cogeneration is also being marketed heavily and there is a high level of interest in the fuel cell.

Region Five: Illinois, Indiana, Michigan, Ohio, Wisconsin, and Minnesota

The demand for natural gas in the commercial sector is higher in Region Five than in any other part of the nation. The reasons for this are basically the same as in the residential sector: large population, cold winters, and low gas prices. Projected increases in natural gas and oil prices, as well as a projection for a decrease in commercial electricity prices, will make electricity more competitive in the space heating market. This is extremely important because space heating is the largest end use in the commercial sector.

Commercial electricity prices in the region are expected to fall through 2000. After the year 2000, prices for all fuels are expected to rise, but the increases will be steeper for the fossil fuels. This outcome will more than likely enhance electricity's relative price position and allow electricity to capture heating market share from oil and natural gas.

Gas-fired space-conditioning systems are currently the norm for new commercial buildings, but there is movement in the direction of electric technologies. Increased efficiency of both buildings and systems leads to lower heating loads, which shifts some of the total cost burden from fuel costs to capital costs. Electric furnaces are the lowest cost systems to install and thus will gain share in the construction market.

Region Six: Arkansas, Louisiana, Oklahoma, Texas, and New Mexico

Commercial demand in Region Six accounts for over 5 percent of total energy consumption, and natural gas supplies 38 percent of the sector's needs. Electricity is the dominant fuel in this market, averaging 45 percent. Energy efficiency in this sector is expected to improve as the fuel consumption per square foot of floor space declines by roughly one-half percent per year.

Nearly all of the petroleum consumption in the commercial sector is devoted to space heating requirements. Due to the slow turnover of the commercial building stock, natural gas is not likely to penetrate the existing oil-heated building market rapidly. In the long run, gas will benefit from replacement of existing equipment. Natural gas should become more attractive relative to distillate fuel oil in space heating applications, because of its clean-burning properties, lower costs of operation, and lack of storage requirement.

This region expects the demand for cogeneration and fuel cells to increase, as the economics improve and seasonal pricing is emphasized to reflect marginal supply costs. Also, the demand for space cooling in commercial applications is expected to grow, with the advent of new technologies like packaged cogeneration systems, heat pumps, and engine-driven chillers. Gas cooling and/or combined cooling and heating technologies are likely to account for a great share of the increase in commercial gas consumption.

Overall, commercial demand for natural gas is projected to increase 1.1 percent annually through the year 2000.

Region Seven: Iowa, Kansas, Missouri, and Nebraska

Commercial consumption accounts for 24 percent of total natural gas consumption in this region, and is expected to grow at an annual rate of 3 percent over the next 10 years. Commercial gas consumption is largely a function of general economic conditions and the changes in the growth of commercial square footage.

Gas cogeneration is a potential market, but not substantial until the economics improve. The biggest potential commercial application expected by this region is in gas consumption by vehicles, due to amendments to the Clean Air Act Amendments of 1990 and increasing national concern over the environment.

The federal government will also establish a much broader program promoting clean fuels in 22 urban areas across the country. Under this program, which begins in the late 1990s and covers 31 percent of the total fleet vehicles, fleets of 10 or more vehicles capable of central refueling will be required to purchase an increasing percentage of "clean fuel" vehicles. While federal laws are not directly affecting alternative vehicles in the Midwest, the general environmental concern nationally and the interest in developing pilot programs to test the technical/economic viability of alternative vehicles have indirectly impacted the Midwest.

Region Eight: Colorado, Utah, Wyoming, Montana, North Dakota, and South Dakota

The commercial market in this region is characterized by high saturation for space heating, minimal competition from other energy sources and minimum number of markets that do not have natural gas as an option. The regional industry needs to focus on a strategy to maintain and increase market share, while minimizing competition from other energy sources.

Opportunities exist in gas cooling, small cogeneration units, and electric integrated resource planning as a result of Demand Side Management programs. These programs provide a significant opportunity for natural gas to increase its market share in this sector. In developing incremental sales through DSM programs and the additional gas cooling, the key drivers are to develop equipment that can be installed at a competitive rate with electric equipment. There is also a great need to convince builders and the ultimate building owners of the long-term economic benefits of natural gas.

Region Nine: California, Arizona, and Nevada

During the base period (1988-1990), commercial energy demand in Region Nine increased at an average 1.6 percent per year. In

1990 total energy demand was over 700 trillion BTU, representing about 5 percent of the region's primary energy usage. Natural gas captured 43 percent of the commercial market share.

Energy conservation efforts and technological advances in electricity applications have contributed to a slowly declining market share in the past decade. Technological advances in gas applications are slow to develop, due to minimal R&D efforts, and have been sometimes economically unattractive once developed as a result of first cost disadvantage. However, many companies in Region Nine are offering financial incentives for new gas technologies, such as gas cooling equipment, to offset the initial costs.

The major commercial sector end uses include space conditioning (heating and cooling), water heating, cooking, and process drying.

Between 1988 and 1990, commercial cogeneration increased from 20 to 25 percent of the total cogeneration load in Region Nine. Hospitals were the single largest commercial cogeneration segment accounting for 26 percent of commercial cogeneration gas use.

Commercial penetration of the fuel cell has begun in Region Nine with the installation of ten 200-kilowatt molten-carbonate fuel cell units in commercial applications.

Region Ten: Idaho, Washington, and Oregon

Electricity accounts for 50 percent of the energy consumed in the region's commercial sector. Electricity competes successfully in all end uses including space heating, which is dominated by oil or natural gas in most other parts of the country.

A major reason for electricity's dominance in the region is its low price. The price is expected to fall through 2000.

Despite the large demand for electricity, natural gas dominates commercial space heating. However, as technologies improve and electric systems become more competitive as the relative price of electricity declines, this dominance will wane. Gas furnaces will then be the second choice technology.

The replacement market will cushion gas's decline in the space heating market. There is a substantial same-system bias in the replacement. Since gas furnaces account for the majority of systems up for replacement, the largest number for replacement systems will be gas-fired.

Chapter Four
Industrial Sector

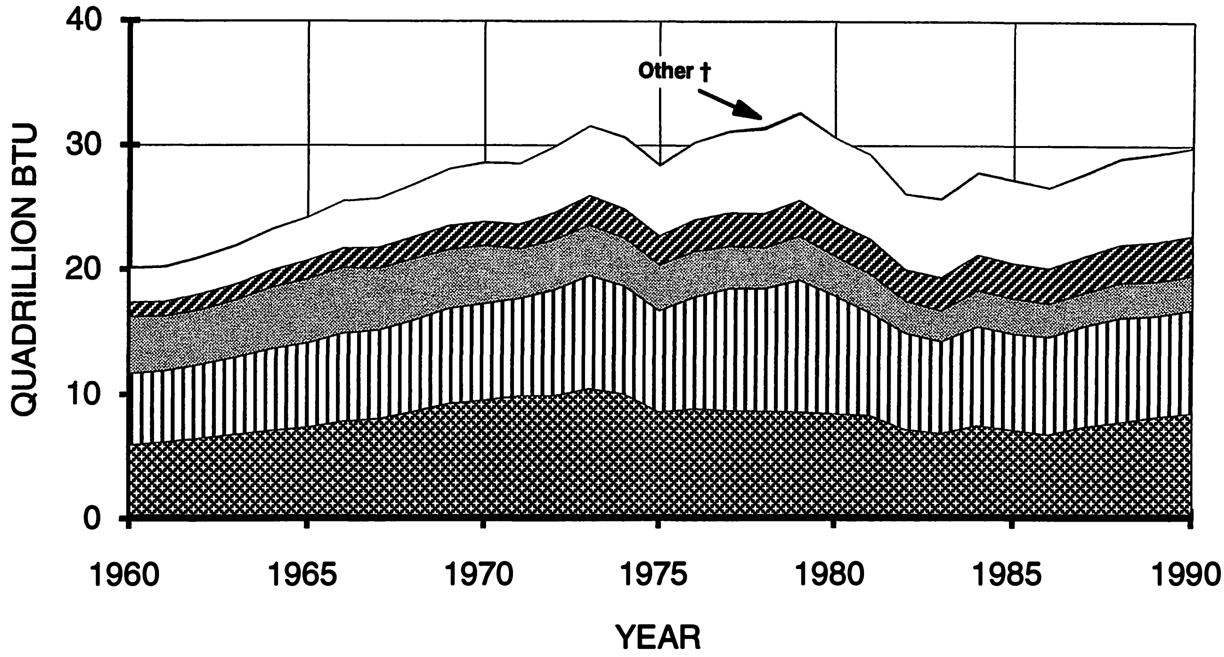
The industrial sector includes energy materials used in the manufacturing and mining industries of the United States. In addition, fuels not easily allocated to other sectors such as farm and miscellaneous uses are generally aggregated into industrial energy consumption. These materials are consumed not only for fuel to provide heat and steam to industrial processes but also for specialty uses such as chemical feedstocks, asphalt, lubricants, fuel for off-highway vehicles, and other applications. In 1990, according to the State Energy Data System (SEDS) published by the Energy Information Administration (EIA), industrial energy consumption, including an allocated share of electric utility generating losses, was 29.8 quadrillion BTU (QBTU) and accounted for about 37 percent of total U.S. energy demand. On a net basis (excluding electric generating losses), natural gas and oil represent the largest energy shares at 37 and 36 percent, respectively, followed by electricity at 15 percent and coal at 12 percent. In addition to conventional energy sources, which are reported and captured in published government data series, about 2 QBTU of nonconventional fuel is currently used in the sector. About three quarters of this fuel is biomass material consumed in the paper industry, with the remaining consumption scattered across a wide range of fuels such as other biomass, geothermal, wind, and municipal solid waste.

Following a period of continuous growth through the early 1970s, industrial energy consumption has been characterized by periods of growth and sharp declines for the last 20 years as shown on Figure 4-1. The declines have been primarily driven by economic cycles and the impacts of the oil price spikes in 1973 and 1979. In addition, significant improvements in energy efficiency and a shift of industrial activities toward a less energy intensive mix has lowered overall energy demand. The net result of the economic and efficiency trend is a 1990 net industrial energy demand of about the same level as in 1975 in spite of a 65 percent increase in industrial activity.

OVERVIEW

Model Results

The NPC Model runs for Reference Cases 1 and 2 project total lower-48 industrial natural gas demand ranging from 8,908 to 6,082 trillion BTU (TBTU) in 2010 respectively. The results and assumptions used in the model projections are discussed in detail in Chapter Eight of this report. The model summarizes results in three broad categories: boilers, cogeneration, and process/other uses. Model results are presented in Table 4-1. The difference between the two model scenarios is driven by the economic and efficiency assumptions in the two Cases. Reference Case 1 is based on a 2.7 percent per year industrial production growth between 1990 and 2010 and energy intensity and industrial mix trends roughly consistent with the trends observed between 1983 and 1990. Reference Case 2 is based on a 2.25 percent per year industrial production growth



* Does not include self generated electricity consumption.
† Other excludes non-commercial fuels.
SOURCE: State Energy Data System, Energy Information Administration.

Figure 4-1. Industrial Sector Energy Demand.

and energy intensity and industrial mix trends roughly consistent with the trends observed between 1973 and 1980. In both Cases, assumptions and model results yield delivered natural gas prices to industrial customers that keep fuel switchable customers burning gas. No significant new technologies were included that would either increase or decrease the natural gas market share. The significant drivers of future energy demand in the industrial sector; overall industrial growth, industrial output mix, and current fuel use patterns are discussed in more detail in the rest of the Overview section.

TABLE 4-1

NPC MODEL RESULTS*
LOWER 48 INDUSTRIAL SECTOR
GAS DEMAND-TBTUS

	1990	2010 Reference Case 1	2010 Reference Case 2
Boilers	2,831	3,783	2,224
Cogeneration	748	1,488	1,447
Process Use	3,467	3,637	2,411
Total Demand	**7,046**	**8,908**	**6,082**

* Excludes lease and plant fuel.

Industrial Activity Measurement

The common and closely followed measure of industrial activity is the Federal Reserve Board's Index of Total Industrial Production commonly referred to as the FRB index. This index provides a single series indicating the relative value of the industrial sector to the economy by combining physical outputs of various industries through a dollar weighting process. Each measured physical output is related to a dollar value in a base year depending on the estimated value of the output. The total dollar value of all the measured outputs in the base year is assigned the index number of 100. As the physical outputs of the various segments change over time, the dollar weighted total is recalculated and compared to the base year total value, yielding the composite index. The FRB index is estimated monthly by the Federal Reserve Board. Periodically (every five to ten years) all series are reweighted to reflect value/unit output changes and the index is re-benchmarked. In addition, weighting changes are also made on a more frequent basis to account for significant changes in output mix between the major updates.

While serving as a useful measure of the overall industrial contribution to the economy, the total FRB index has significant limitations as a measure or predictor of energy consumption. As a result of the dollar weighting aggregation, high value added industrial activities, which may consume little energy on a unit basis, contribute more to the index than low value added energy intensive industries. In addition, currently about 8 percent of the FRB index is from utility sales that do not contribute to energy demands reported in the industrial sector.

Industries are normally classified based on the industrial groups identified in the *Standard Industrial Classification Manual, 1987*, published by the Office of Management and Budget. The classifications commonly called SIC codes group industries together based on similar manufacturing activity.

Industrial Activity Measurement Masks Underlying Energy Trends

Table 4-2 shows the relative contribution to the total FRB index of various major industries for the current base year (1987) along with energy and natural gas consumption data. The manufacturing industries are ordered from highest to lowest energy consumption. As shown on the table, the top five energy consuming industries in 1988 (petroleum, chemicals, primary metals, paper, and stone, clay, and glass) accounted for almost 12 QBTU out of the 15.5 QBTU or about 77 percent of the total energy reported for manufacturing. If feedstocks were included, the share would be even higher since virtually all feedstock consumption is in the top five industry groups. As indicated on the table, these industries accounted for less than 20 percent of the composite dollar weighted total FRB in 1987. The second five energy consuming industries accounted for about 15 percent of energy consumption and contributed about 35 percent of the total FRB, with the remaining ten manufacturing industries accounting for 8 percent of energy demand and contributing almost 30 percent of the total FRB. Natural gas consumption parallels the energy trends with the top five energy consuming industries consuming 73 percent, the second five 19 percent, and the remaining industries 8 percent of natural gas consumption.

Data for the mining industries are shown at the bottom of the table. The largest contribution to energy and natural gas demand from mining is from SIC 13, oil and gas extraction. This industry (oil and gas production and natural gas liquids extraction) ranks fifth overall in total energy consumption and is second only to chemicals in natural gas consumption. In total, mining contributes about 8 percent of the total FRB, with both the FRB and energy contribution dominated by SIC 13.

Since there is a large disparity between energy use and natural gas consumption and the dollar weighted output contribution of the industrial sector, the mix of industries producing in the economy is a significant factor in understanding historical and projecting future industrial energy demands.

Manufacturing Moving Towards Less Energy-Intensive Output Trend

Figure 4-2 illustrates the impact of the changing mix of two-digit SIC industrial output on the energy-intensity of manufacturing industries. The solid line on the chart shows the trend of all manufacturing on a dollar output weighted basis as measured and published by the Federal Reserve Board. The upwardly sloping dashed line shows a similar trend calculated on an energy weighted basis. This line was calculated assuming a weighting equal to the 1988 Manufacturing Energy Consumption Survey (MECS) energy use and indexed at 1987 = 100 to compare to the FRB series. The line shows the trend in manufacturing energy consumption as a result of the changing mix of industrial output exclusive of energy conservation.

The growth rate table on the chart illustrates the trends in the two series for three distinct time periods: 1960-1979, 1979-1983, and 1983-1990. During the period of 1960-1979,

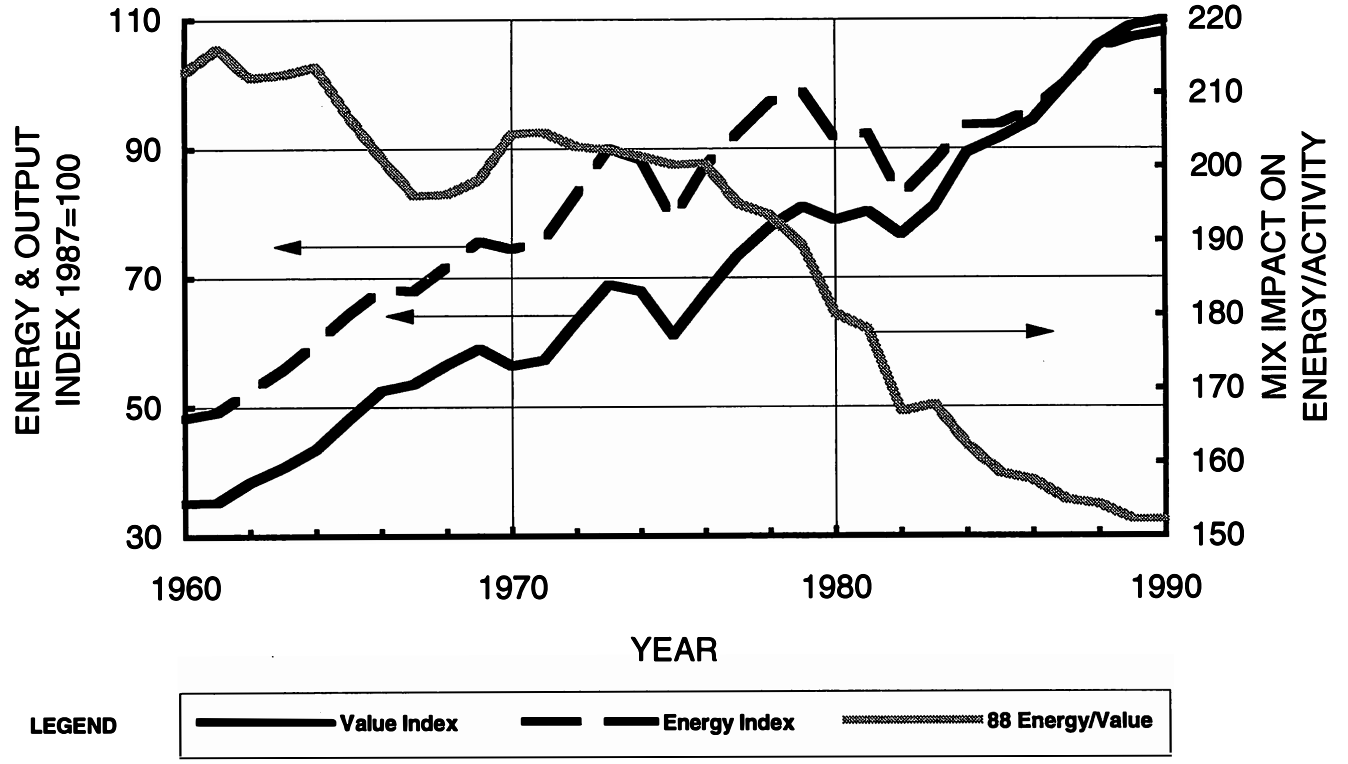
TABLE 4-2

COMPARISON OF INDUSTRIAL ENERGY AND NATURAL GAS CONSUMPTION TO OUTPUT SHARES

SIC Code	Description	Energy Consumption (Trillion BTU)	Natural Gas (BCF)	1987 Share of Production Index†
Manufacturing Industries		**1988 MECS***		
29	Petroleum and Coal Products	3,122	702	1.3
28	Chemicals and Allied Products	2,862	1,466	8.6
33	Primary Metal Industries	2,622	720	3.3
26	Paper and Allied Products	2,347	415	3.6
32	Stone, Clay, and Glass Products	1,000	451	2.5
	Top Five Energy-Consuming Industries	**11,953**	**3,754**	**19.3**
20	Food and Kindred Products	996	473	8.8
24	Lumber and Wood Products	404	34	2.0
37	Transportation Equipment	349	134	9.8
34	Fabricated Metal Products	343	197	5.4
35	Industrial Machinery and Equipment	276	123	8.6
	Second Five Energy-Consuming Industries	**2,368**	**961**	**34.5**
22	Textile Mill Products	275	90	1.8
30	Rubber and Misc. Plastics Products	252	107	3.0
36	Electronic and Other Electric Equipment	215	82	8.6
27	Printing and Publishing	115	47	6.4
38	Instruments and Other Related Products	113	31	3.3
25	Furniture and Fixtures	63	22	1.4
23	Apparel and Other Products	54	21	2.4
39	Misc. Manufacturing Industries	41	19	1.2
21	Tobacco Products	24	2	1.0
31	Leather and Leather Products	16	5	0.3
	Remaining Manufacturing Industries	**1,168**	**426**	**29.5**
	Total Manufacturing	**15,489**	**5,141**	**83.3**
Mining Industries		**1987 Census***		
10	Metal Mining	119	33	0.3
12	Coal Mining	163	1	1.2
13	Oil/Gas Extraction	1,381	1,011	5.7
14	Other Mining	305	85	0.7
	Total Mining	**1,968**	**1,130**	**7.9**
Other Industries				
91	Government Ordinance	?		1.2
491	Electric Utility Sales	-		6.0
492	Gas Utility Sales	-		1.6
	Total Other	-		**8.8**
Total All Industries In FRB Index				**100.0**

* Data from the 1988 MECS excluding feedstocks and including non-commercial fuels. MECS data are not directly comparable to industrial sector energy consumption data reported in other series. 1987 Census refers to data from the 1987 *Census of Mineral Industries* published by the Department of Commerce.

† Share totals may not add due to independent rounding.



	Compound Annual Growth Rates (percent per year) 60-79	79-83	83-90
Mfg FRB	4.5	0.0	4.5
Eng Index	3.8	(3.0)	3.0
En/Output	(0.6)	(3.0)	(1.4)

NOTES: Mfg FRB: Federal reserve board published index for all manufacturing.
Eng Index: Sum of 1988 MECS Energy data by 2 digit SIC times published FRB by 2 digit SIC, indexed 1987=100.
En/Output: Sum of 1988 MECS Energy data by 2 digit SIC times published FRB by 2 digit SIC, divided by published FRB for all manufacturing.

Figure 4-2. U.S. Manufacturing Mix Change.

manufacturing grew at about the same rate as total industrial production with the energy index tracking roughly in step with the FRB index. During the period of 1979-1983, significant change took place in the manufacturing sector of the United States both in energy use and manufacturing output. As a result of the back-to-back recessions in 1980 and 1982, overall output of the manufacturing sector did not grow between 1979 and 1983. Over the same period, the energy index fell at an average rate of 3.0 percent per year. The reduction of the energy weighted index illustrates the significant restructuring of American industry that occurred across the 1979-1983 time period. Output from heavy industry was reduced, with less energy-intensive, higher value added industries becoming a much more significant part of manufacturing output. From 1983-1990, the economy continuously expanded. Overall manufacturing FRB grew at 4.5 percent per year, the same rate as from 1960-1979, and about 20 percent faster than the total index of industrial production. The energy output index, however, fell at a rate of more than twice the 1960-1979 rate, indicating a continued shift towards a less energy-intensive manufacturing mix.

Future Output Mix Key Variable in Size of Potential Industrial Energy Market

Figure 4-3 shows the impact of various future manufacturing mix change assumptions on overall energy intensity. If all manufacturing industries were to grow at the same rate in the future, the result would be a horizontal line at an index level of 1. The plotted lines indicate the trends expected based on the observed changes in the manufacturing sector for the three time frames discussed previously. While it is unlikely that mix changes on the order of those observed between 1979-1983 will occur in the future, there is no consensus on the overall future trend. However, it is clear that the future of the mix of output in the industrial sector is a key variable in determining the size of the future industrial energy market.

Conservation Measurement Complex, But Driven by Conventional Economic Calculations

The industrial sector is perhaps the most easily understood sector regarding the implementation of energy conservation technologies since the sector responds to classic economic calculations. Energy efficiency investment decisions are made in competition with other investment opportunities based on return on investment and competition for other resources (manpower, etc.). In general, companies in the major energy-consuming manufacturing SICs are sophisticated energy users who evaluate energy costs relative to other costs on a routine basis. These users typically have multiple fuel options and a variety of potential projects available to reduce overall energy use and cost at the site. In some of the less energy-intensive industries, energy costs are a smaller portion of overall costs and probably receive somewhat less attention. However, given the extremely competitive nature of the industrial sector and the large amount of attention focused on energy consumption over the last twenty years, it is unlikely that any industrial facility today is unaware of its energy needs, opportunities to reduce consumption, or the potential for diversifying fuel mix.

Figure 4-4 shows the trend of industrial energy demand (1990 SEDS) relative to the total FRB. This trend reflects the mix change between the broad categories of industrial output discussed previously and energy conservation. In addition, there have been other changes within the broad two-digit SIC categories as U.S. manufacturers have shifted their output toward higher value products. For example, U.S. steel output is more heavily oriented towards higher value and quality steels than was the case 20 years ago. This same trend is typical

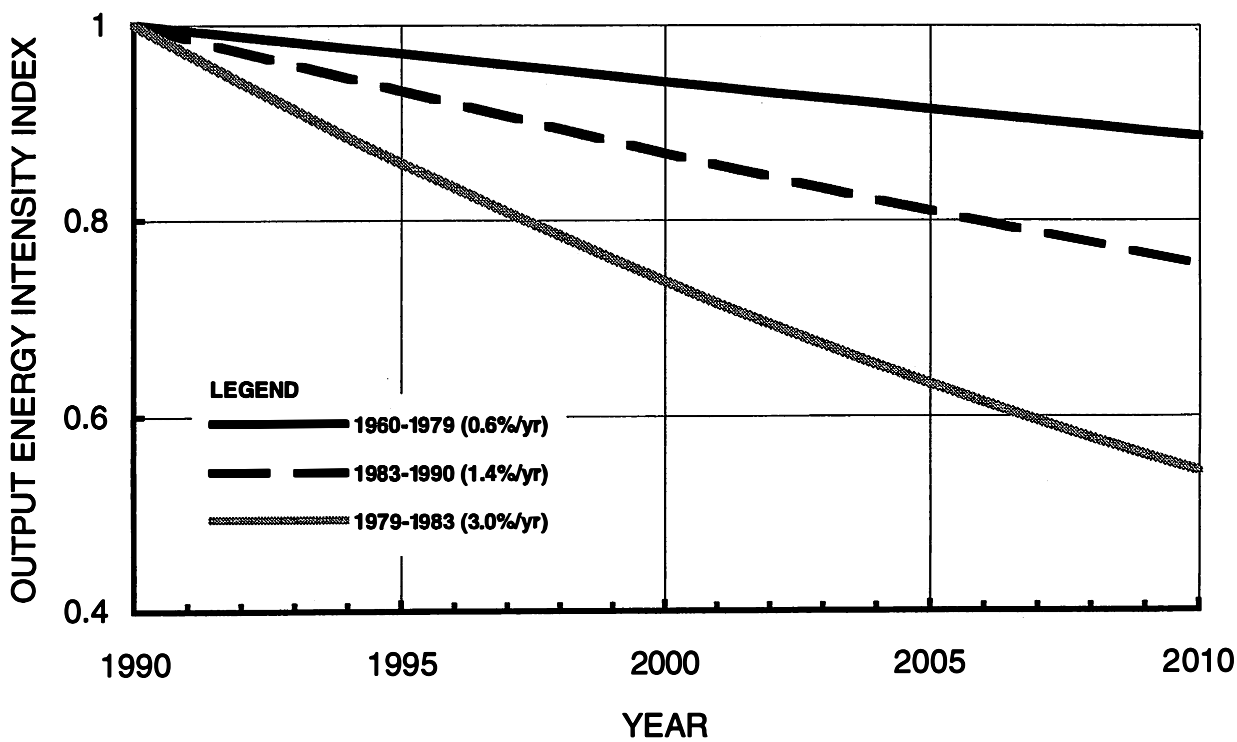
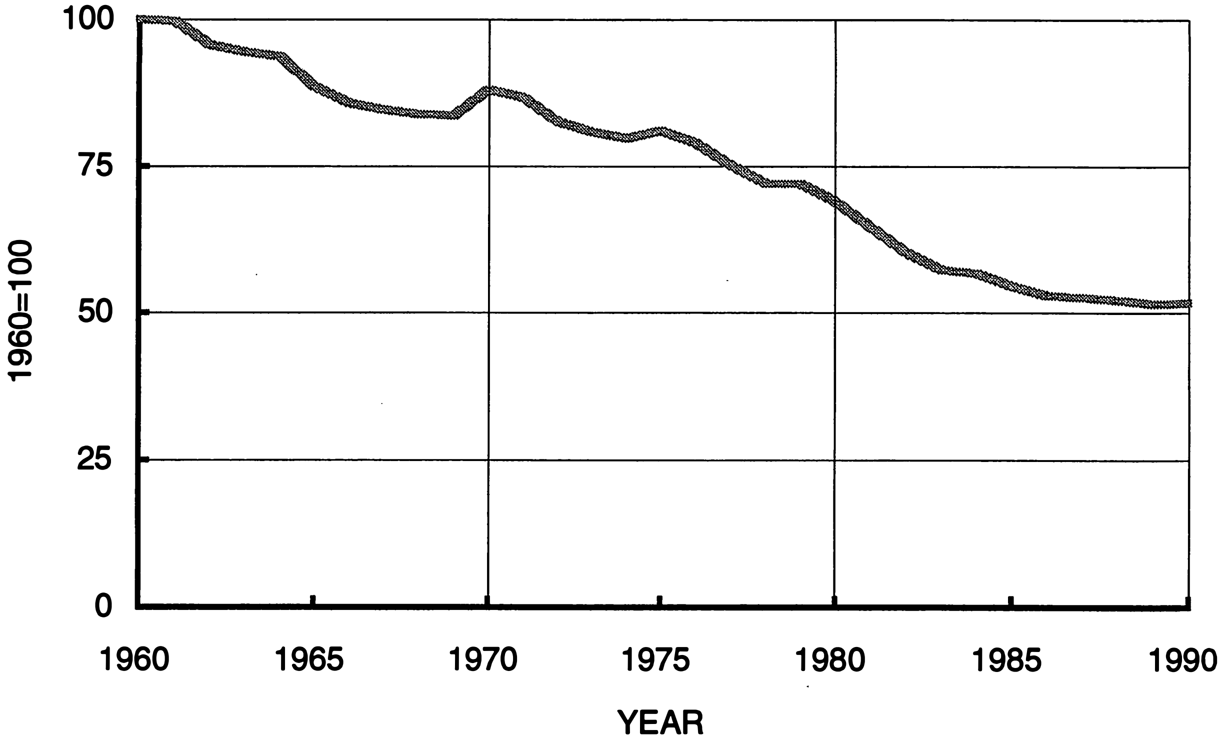


Figure 4-3. Potential Mix Change Impacts.



	Compound Annual Growth Rates (percent per year)		
	60-79	79-83	83-90
En Index	(1.7)	(5.5)	(0.0)

Figure 4-4. Industrial Energy/Unit Activity.

for most industries and reduces the apparent unit energy consumption when using a dollar output divisor. While the energy impacts of these "internal" SIC mix changes have not been generally studied, they have probably contributed to the decline in energy consumption/output ratio.

MECS develops energy trends per constant dollar of shipments data as part of its energy use analysis of the manufacturing industries. The intensity ratios show an average improvement for all manufacturing of about 5 percent per year from 1980 to 1985 and about 1.5 percent per year from 1985 to 1988. These ratios are based on purchased energy and do not include the impacts of any change in consumption of locally produced fuel.

In late 1990, the EIA conducted a series of roundtables with the major energy consuming industries that discussed, among other things, energy efficiency. The following discussion, summarizing the results of the round table, was published in *Changes in Energy Intensity in the Manufacturing Sector 1980-1988* and points out the complex interaction of fuel use in the manufacturing sector.

Among the factors noted that increase or facilitate energy efficiency improvements are:

- Improved energy management consists of better equipment maintenance, improved insulation, lowering thermostats, routine energy audits, and conservation goals.
- Computer controls and instrumentation allow companies to track energy use and keep processes running at optimal efficiency.
- Heat recovery and heat exchange involves lowering stack temperatures, the installation of waste-heat recovery boilers, and condensate recovery.
- Improvements in electricity cogeneration, including switching to gas turbines, have been an important factor in improving energy efficiency.
- Increases, renovations, and turnover in production capacity commonly incorporate technological advances and improved

operational techniques that have allowed many industries to increase energy efficiency.

The participants also cited several factors that directly increase energy consumption per unit of product and, therefore, decrease energy efficiency. Among these factors are:

- Environmental regulations, which often involve a direct energy cost with no increase in output, may have a negative impact on energy efficiency. The implementation of these regulations often absorbs financial resources that might otherwise be used for projects to improve energy efficiency.
- Improvements in product quality frequently result in increased energy consumption per unit of product produced. Such improvements frequently result in a higher value of the product so that total energy cost as a percentage of the price of the product decreases. However, energy consumption per unit of product increases, resulting in decreased energy efficiency.
- Overutilization of capacity frequently results in decreased energy efficiency because previously idle underused equipment and processes, which frequently are less energy-efficient, are used in order to get extra production. Despite the inefficiency, such activities are profitable because extra output is obtained with no capital investment, and because energy costs are often a small proportion of total costs.
- Weather conditions affect the energy consumption of building conditioning systems. This factor is more important in those industries not dominated by process energy use but have large floor space areas. Examples of such industries include the motor vehicles industry and electrical and electronic equipment manufacturers.
- Economic conditions may adversely affect energy efficiency in a number of ways. Energy prices and availability determine the incentives for investing in projects that conserve energy. Expanding markets require the expansion of capacity, which improves energy efficiency by bringing in new technologies. Conversely, economic stagnation is typically coupled with a slower rate of energy-efficiency improvement. In general, interest rates and the availability of capital also affect corporate investment decisions, including investments in energy conservation.
- Energy efficiency potential continually decreases as a process approaches its theoretical limit of efficiency. Most of the "easy" efficiency gains were implemented in the late 1970s and the early 1980s.

The EIA summarizes the participants' comments as follows:

> Thus, according to the round table participants, energy efficiency in the manufacturing sector is a function of technological advancements, economic conditions, and a variety of production factors. Most manufacturers view energy from a purely economic perspective. Accordingly, energy investments are subject to return-on-investment calculations and must compete with other projects for scarce capital. Energy investments are also subject to risk analysis because of the volatility of energy prices. Ultimately, what motivates manufacturers actions with regard to energy is energy cost, rather than efficiency or consumption. Improvements in energy efficiency often result from projects whose primary purpose is to increase production, to improve quality, or to replace worn-out equipment. Few major capital expenditures are justified solely on the basis of improving energy efficiency.

As pointed out in the summary, energy is only one of many factors that a business must contend with in its day to day operations. Most observers would agree that market success requires the pursuit of an optimum combination of all factors rather than focused attention on a single input.

Industrial energy efficiency will improve with time. However, progress will be difficult to quantify accurately as a result of the complex interaction of numerous factors that impact energy use as well as the difficulty of measuring outputs on a consistent physical basis.

Oil Demand Reported in Industrial Sector Predominantly for Specialized Uses

Table 4-3 shows 1990 industrial oil demand by federal region grouped by oil type developed from the source documents. The data closely match the SEDS totals for the continental U.S. While virtually all industrial fuels compete with each other at the margin, there are a number of end uses where one form of energy has an inherent advantage over its competitors. Table 4-4 reorganizes the oil demand data into product categories with similar end-use characteristics. The top portion of the table summarizes oil demand for use categories where oil has a market advantage over competing fuels as a result of the nature of oil itself. These markets are:

Refining: During the refining process, byproduct, low pressure, light hydrocarbon gas (still gas) is produced and coke is deposited on catalyst. These materials are consumed within the refinery since there generally is not a commercial outlet available. In 1990, these two products accounted for almost 20 percent of the oil consumption in the industrial sector. Since these fuels cannot be easily sold commercially, their substitution potential is limited.

Feedstocks: About 39 percent of the oil demand in the industrial sector is for chemical feedstock use, primarily for the production of ethylene and other olefins from steam cracking. While chemicals can be made from other feedstock sources and processes, it is unlikely that alternative feedstocks will make significant inroads into this market.

Mobile Use: Significant quantities of distillate are used within the industrial sector to provide fuel for off-road vehicles and other equipment needs. To the extent that these uses are in fixed locations, natural gas may be able to compete. However, it is generally believed that the bulk of these fuels is consumed at construction sites and other remote locations, where oil because of its portability has an economic advantage over gas.

Farm Use: Oil use on farms is allocated to the industrial sector in SEDS. Most of the farm use is diesel, which is used in mobile equipment. In addition, farms tend to be remote and widely spaced, making this market an unlikely one for gas penetration.

Gas Utility Use: Gas utilities use liquefied petroleum gas (LPG) to provide peak capability on the natural gas delivery system. Additional storage might obviate the need for some of this LPG, but it is unlikely that its use will be displaced from the role of increasing the peak day delivery capability of the natural gas system.

Specialty Uses: A variety of oils accounted for in the industrial sector can be characterized as specialty oils. These include asphalt, lubricants, special naphthas (solvents), and other uses. These uses, which account for almost 20 percent of oil demand, are unlikely to be impacted to any significant degree by fuel substitution.

The remaining oil end uses, which totaled 400 thousand barrels per day (MB/D) and accounted for less than 10 percent of industrial oil demand in 1990, are summarized on the bottom half of the table.

Quantity of Bulk Oil Use in The Industrial Sector Has Been in Steady Decline

The industrial bulk uses of oil as defined in Table 4-4 have been steadily declining since 1979, as shown on Figure 4-5. In 1980, the EIA changed its data reporting system for kerosene and fuel oil sales and hence it is not possible to extend the chart prior to 1979. The table shows the numerical data on the demand trends for the period from 1979 to 1983 and for 1983-1990. From 1979 to 1983, demand for all types of industrial oil was decreasing in response to the oil price spike in 1979 and the back-to-back recessions of the early 1980s. Since 1983, non-bulk uses of oil have increased to about 400 MB/D above their 1979 total. Bulk oil use, however, continued its decline across the entire period to its current level of 400 MB/D, 1 million barrels per day below the

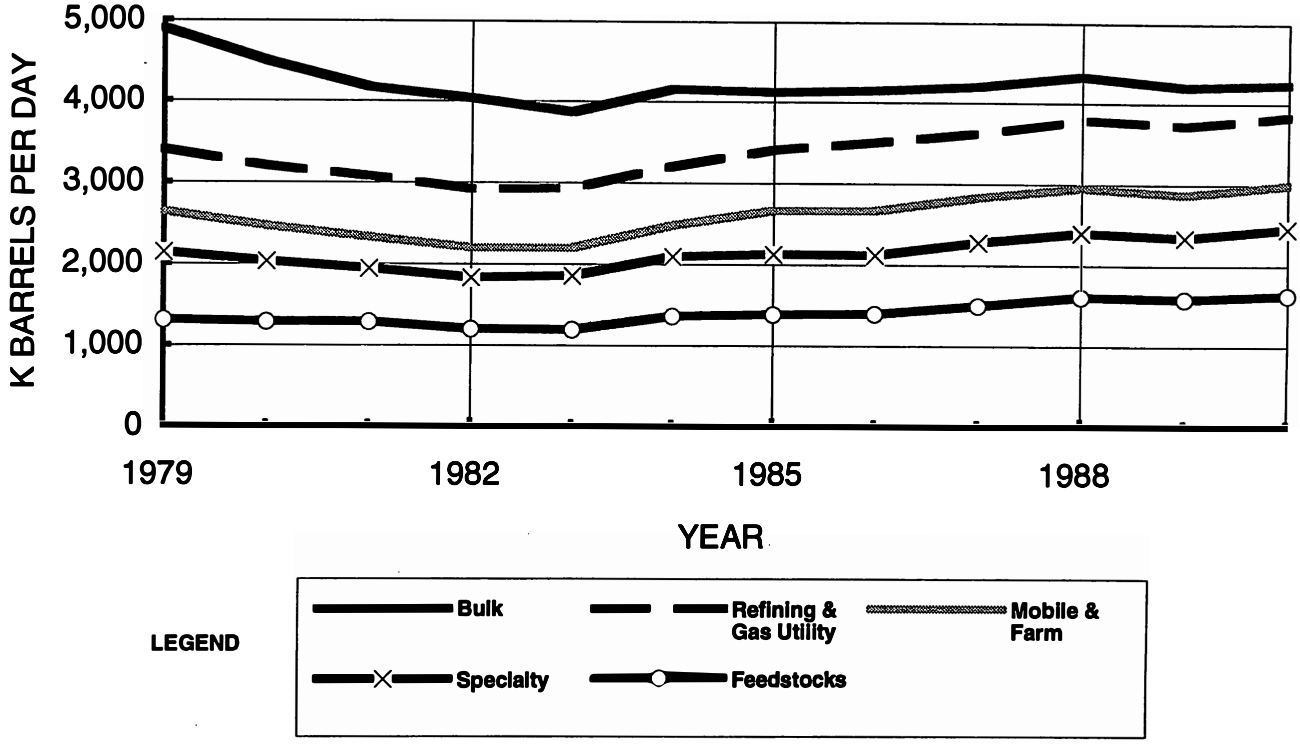
TABLE 4-3
1990 INDUSTRIAL OIL DEMAND BY FEDERAL REGION

	Oil Demand (Thousand Barrels per Day)											MMBTU/ Barrel	U.S. TBTU	Source/Comments
	New England	NY/NJ	Mid Atlantic	South Atlantic	Midwest	S.West Central	Central	North Central	South Pacific	North-West	Cont U.S.			
Still Gas-Fuel	0	22	30	22	94	268	14	23	116	20	609	6.000	1334	Total Still Gas by PADD EIA PSA.
Still Gas-Chem Feed	0	4	6	1	0	46	0	0	3	0	60	6.000	131	Chem Feed Estimate, last reported value 1985.
Total Still Gas	0	26	36	23	94	314	14	23	119	20	669	6.000	1465	Regions prorated based on refinery capacities.
Ethane-Industrial	1	0	0	0	0	0	0	0	0	0	1	3.082	1	LPG Data from 1990 API LPG Sales Report.
Ethane-Gas Utility	0	0	0	0	8	0	1	0	1	0	10	3.082	11	
Ethane-Misc.	0	0	0	0	0	0	0	0	0	0	0	3.082	0	
Ethane-Chem Feed	0	0	0	0	5	478	16	0	0	0	499	3.082	561	
Propane-Industrial	3	2	6	18	13	12	7	4	11	3	79	3.836	111	
Propane-Gas Utility	3	0	0	1	1	2	1	0	0	0	8	3.836	11	
Propane-Misc.	0	0	0	0	0	0	0	0	0	0	0	3.836	0	
Propane-Chem Feed	1	6	7	11	24	329	8	2	8	0	396	3.836	554	
Butane-Industrial	0	0	1	1	2	4	0	1	11	0	20	4.326	32	
Butane-Gas Utility	0	0	0	0	0	0	0	0	0	0	0	4.326	0	
Butane-Misc.	0	0	0	0	0	0	0	0	0	0	0	4.326	0	
Butane-Chem Feed	0	1	0	1	4	80	7	1	0	0	94	4.326	148	
C5+ Chem Fd	0	0	0	0	2	38	11	0	0	0	49	5.418	97	
Total LPG	8	9	14	32	59	941	51	8	31	3	1156	3.617	1526	
Mogas-Industrial	2	4	7	19	17	17	10	8	10	4	98	5.253	188	Agricultural, Industrial/Commercial and Construction Mogas reported by DOT.
Kerosene-Industrial	0	2	0	1	1	1	0	0	0	0	5	5.670	10	
Kerosene-Farm	1	0	0	0	0	0	0	0	0	0	1	5.670	2	Kerosene data from 1990 EIA Fuel Oil
Kerosene-Other	1	0	0	0	0	0	0	0	0	0	1	5.670	2	and Kerosene Sales Report. (FOKS)
Total Kerosene	2	2	0	1	1	1	0	0	0	0	7	5.670	14	
Dist #1-Industrial	0	0	0	0	2	0	0	2	0	0	4	5.825	9	Distillate data from 1990 EIA FOKS.
Diesel-Farm	1	2	6	34	37	37	32	18	25	13	205	5.825	436	
Diesel-Construction	3	5	9	18	15	22	4	5	17	4	102	5.825	217	
Diesel-Other	0	0	0	4	1	2	0	0	2	4	13	5.825	28	
Equipment Diesel	2	2	13	24	15	17	2	9	21	4	109	5.825	232	
Dist #2-Industrial	5	4	7	12	6	53	2	4	4	2	99	5.825	210	
Dist #2-Farm	0	2	1	0	3	0	1	1	0	0	8	5.825	17	
Dist #2-Miscellaneous	0	0	0	0	0	0	0	0	0	0	0	5.825	0	
Dist #4-Industrial	1	2	1	1	0	0	0	0	2	0	7	5.825	15	
Total Distillate	12	17	37	93	79	131	41	39	71	27	547	5.830	1164	
HFO-Industrial	24	21	24	35	18	8	3	1	4	6	144	6.287	330	HFO data from 1990 EIA FOKS. Standard
HFO-Oil Company	0	1	6	1	8	0	0	1	1	1	19	6.287	44	conversion factor used assumes high sulfur
HFO-Other	0	0	0	0	0	0	0	0	0	0	0	6.287	0	fuel oil and overstates BTU consumption.
Total HFO	24	22	30	36	26	8	3	2	5	7	163	6.287	374	
Coke-Catalytic	0	11	15	8	32	101	5	7	28	5	212	6.024	468	Coke by PADD EIA PSA.
Coke-Market	0	2	7	6	48	31	7	6	15	3	125	6.024	275	Regions based on refinery capacities.
Crude Oil	0	0	0	0	0	0	0	0	21	0	21	5.800	44	Crude oil all in PADD V and assumed in California.
Total Hvy Other	0	13	22	14	80	132	12	13	64	8	358	6.007	785	
Naphtha Chem Feed	1	2	2	37	17	117	4	0	2	0	182	5.248	349	Chem Feed by PADD EIA PSA. Regions based on
Heavy Chem Feed	0	0	0	72	18	259	5	1	0	0	355	5.825	755	population.
Total Hvy Chem Fd	1	2	2	109	35	376	9	1	2	0	537	5.633	1104	
Special Naphtha	2	3	4	11	15	18	4	0	1	0	58	5.248	111	Specialty products by PADD PSA. Regions
Misc Prduct	2	4	4	12	6	25	1	2	1	1	58	5.796	123	generally prorated based on population. Lubes
Lubes	3	6	6	16	11	30	5	1	6	2	84	6.065	186	Industrial/Transportation split based on 90 SEDS.
Asphalt	18	25	51	95	110	58	31	24	50	19	481	6.636	1165	Asphalt distribution based on Asphalt Institute sales.
Wax	0	1	1	3	1	8	0	1	1	0	16	5.537	32	
Total Specialty	25	39	66	137	143	139	41	28	59	22	697	6.358	1617	
Total Oil	74	134	214	464	534	2059	181	122	361	91	4232	5.332	8237	

NOTE: SEDS – EIA State Energy Data System, PSA – EIA Petroleum Supply Annual, API – American Petroleum Institute

TABLE 4-4
1990 INDUSTRIAL OIL DEMAND TABULATION BY SUBSTITUTION POTENTIAL
(Regional Data in Thousand Barrels per Day)

	New England	NY/NJ	Mid Atlantic	South Atlantic	Midwest	S.West Central	Central	North Central	South Pacific	North-West	Cont U.S.	MMBTU/ Barrel	U.S. TBTU
— Special Uses —													
Still Gas-Fuel	0	22	30	22	94	268	14	23	116	20	609	6.000	1,334
Coke-Catalytic	0	11	15	8	32	101	5	7	28	5	212	6.024	466
Total Refining	**0**	**33**	**45**	**30**	**126**	**369**	**19**	**30**	**144**	**25**	**821**	**6.007**	**1,800**
Still Gas-Chem Feed	0	4	6	1	0	46	0	0	3	0	60	6.000	131
Ethane-Chem Feed	0	0	0	0	5	478	16	0	0	0	499	3.082	561
Propane-Chem Feed	1	6	7	11	24	329	8	2	8	0	396	3.836	554
Butane-Chem Feed	0	1	0	1	4	80	7	1	0	0	94	4.326	148
C5+ Chem Fd	0	0	0	0	2	36	11	0	0	0	49	5.418	97
Naphtha Chem Feed	1	2	2	37	17	117	4	0	2	0	182	5.248	349
Heavy Chem Feed	0	0	0	72	18	259	5	1	0	0	355	5.825	755
Total Feedstocks	**2**	**13**	**15**	**122**	**70**	**1,345**	**51**	**4**	**13**	**0**	**1,635**	**4.348**	**2,595**
Mogas-Industrial	2	4	7	19	17	17	10	8	10	4	98	5.253	188
Diesel-Construction	3	5	9	18	15	22	4	5	17	4	102	5.825	217
Diesel-Other	0	0	0	4	1	2	0	0	2	4	13	5.825	28
Equipment Diesel	2	2	13	24	15	17	2	9	21	4	109	5.825	232
Total Mobile Use	**7**	**11**	**29**	**65**	**48**	**58**	**16**	**22**	**50**	**16**	**322**	**5.658**	**665**
Kerosene-Farm	1	0	0	0	0	0	0	0	0	0	1	5.670	2
Diesel-Farm	1	2	6	34	37	37	32	18	25	13	205	5.825	436
Dist #2-Farm	0	2	1	0	3	0	1	1	0	0	8	5.825	17
Total Farm Use	**2**	**4**	**7**	**34**	**40**	**37**	**33**	**19**	**25**	**13**	**214**	**5.825**	**455**
Ethane-Gas Utility	0	0	0	0	8	0	1	0	1	0	10	3.082	11
Propane-Gas Utility	3	0	0	1	1	2	1	0	0	0	8	3.836	11
Butane-Gas Utility	0	0	0	0	0	0	0	0	0	0	0	4.326	0
Total Gas Utility	**3**	**0**	**0**	**1**	**9**	**2**	**2**	**0**	**1**	**0**	**18**	**3.349**	**22**
Asphalt	18	25	51	95	110	58	31	24	50	19	481	6.636	1165
Coke-Market	0	2	7	6	48	31	7	6	15	3	125	6.024	275
Lubes	3	6	6	16	11	30	5	1	6	2	84	6.065	186
Misc Product		4	4	12	6	25	1	2	1	1	58	5.796	123
Special Naphtha	2	3	4	11	15	18	4	0	1	0	58	5.248	111
Wax	0	1	1	3	1	8	0	1	1	0	16	5.537	32
Total Specialty	**23**	**41**	**73**	**143**	**191**	**170**	**48**	**34**	**74**	**25**	**822**	**6.306**	**1892**
Total Unique Use	**37**	**102**	**169**	**395**	**484**	**1,961**	**169**	**109**	**307**	**79**	**3,832**	**5.311**	**7,429**
— Bulk Fuel —													
Ethane-Industrial	1	0	0	0	0	0	0	0	0	0	1	3.082	1
Ethane-Misc.	0	0	0	0	0	0	0	0	0	0	0	3.082	0
Propane-Industrial	3	2	6	18	13	12	7	4	11	3	79	3.836	111
Propane-Misc.	0	0	0	0	0	0	0	0	0	0	0	3.836	0
Butane-Industrial	0	0	1	1	2	4	0	1	11	0	20	4.326	32
Butane-Misc.	0	0	0	0	0	0	0	0	0	0	0	4.326	0
Total LPG	**4**	**2**	**7**	**19**	**15**	**16**	**7**	**5**	**22**	**3**	**100**	**3.945**	**144**
Kerosene-Industrial	0	2	0	1	1	1	0	0	0	0	5	5.670	10
Kerosene-Other	1	0	0	0	0	0	0	0	0	0	1	5.670	2
Dist #1-Industrial	0	0	0	0	2	0	0	2	0	0	4	5.825	9
Dist #2-Industrial	5	4	7	12	6	53	2	4	4	2	99	5.825	210
Dist #2-Misc.	0	0	0	0	0	0	0	0	0	0	0	5.825	0
Dist #4-Industrial	1	2	1	1	0	0	0	0	2	0	7	5.825	15
Total Kero+Distillate	**7**	**8**	**8**	**14**	**9**	**54**	**2**	**6**	**6**	**2**	**116**	**5.810**	**246**
HFO-Industrial	24	21	24	35	18	8	3	1	4	6	144	6.287	330
HFO-Oil Company	0	1	6	1	8	0	0	1	1	1	19	6.287	44
HFO-Other	0	0	0	0	0	0	0	0	0	0	0	6.287	0
Crude Oil	0	0	0	0	0	0	0	0	21	0	21	5.800	44
Total Heavy Oil	**24**	**22**	**30**	**36**	**26**	**8**	**3**	**2**	**26**	**7**	**184**	**6.224**	**418**
Total Bulk Oil	**35**	**32**	**45**	**69**	**50**	**78**	**12**	**13**	**54**	**12**	**400**	**5.534**	**808**
Total Oil	**72**	**134**	**214**	**464**	**534**	**2,059**	**181**	**122**	**361**	**91**	**4,232**	**5.332**	**8,237**



Industrial Oil Demand Trends

	1979-1983	1983-1990	Total
Feedstocks	(115)	441	326
Specialty	(170)	157	(13)
Mobile/Farm	(156)	194	38
Refining/Gas Util	(37)	115	78
Bulk	(553)	(539)	(1092)
Total	**(1031)**	**368**	**(663)**

Figure 4-5. Industrial Oil Demand (Continental U.S.).

1979 level and less than 10 percent of industrial oil demand.

Other Industrial Fuels Have Niche Markets

Table 4-5 summarizes the regional oil use by the special/bulk distribution shown in Table 4-4 along with the consumption of other fuels in both physical and trillion BTU units. While the reported end-use differentiation is not as great as for oil, certain markets exist for fuels other than oil that have value beyond the inherent BTU content of the fuel:

Gas for Lease and Plant Fuel: A significant quantity of gas reported in the industrial sector (13 percent) is consumed as fuel on production leases and for natural gas liquids extraction plant fuel. Both of these uses are unlikely to be substituted by other fuels with normal market conditions.

Gas for Feedstock Use: Natural gas is the primary feedstock for the production of ammonia, methanol, and acetylene, and is also used in the production of hydrogen in refining and petrochemical plants. Data on consumption for these uses are not publicly available; however, estimates generally fall in the 0.5-0.8 TCF per year range. Major inroads into these markets by competing fuels are unlikely over the next 20 years.

Coal for Coke Plants: Coal is heated to form coke, which is used in the steel making process. The coke acts as a reducing

TABLE 4-5

REGIONAL PHYSICAL VOLUME DISTRIBUTION

	New England	NY/NJ	Mid Atlantic	South Atlantic	Midwest	S.West Central	Central	North Central	South Pacific	North-West	Cont U.S.		Source/Comments
Oil (Thousand Barrels/Day)	74	134	214	464	534	2,059	181	122	361	91	4,232		See Oil Table for References.
Unique	39	102	169	395	484	1,981	169	109	307	79	3,832		
Bulk	35	32	45	69	50	78	12	13	54	12	400		
												BTU/ Cubic Foot	
Natural Gas (Billion Cubic Feet)	81	193	465	866	1,225	3,793	328	218	614	151	7,934	1,030	1990 EIA Natural Gas Annual.
Gas-Industrial	81	192	449	844	1,212	2,956	287	130	591	151	6,893	1,030	
Gas-Lease & Pit Fuel	0	1	16	22	13	837	41	88	23	0	1,041	1,030	
												MMBTU/ Ton	
Coal (Million Tons)	0.3	3.4	28.9	21.3	37.4	6.5	2.9	10.6	3.8	0.8	116	0.000	
Coal-Coke Plants	0.0	1.1	15.9	4.5	16.9	0	0	1.4	0	0	40	26.800	1990 EIA Coal Distribution.
Coal-Other	0.3	2.3	13	16.8	20.5	6.5	2.9	9.2	3.8	0.8	76	22.444	1990 EIA Coal Distribution.
												MMBTU/ Thousand kwh	
Electricity (Billion kilowatt hours) (Purchased)	27.2	47	98.4	207.2	222.6	136.3	37	30	72.2	63.4	941	3.412	1990 EIA Electric Power Annual.
Renewable/Other (Trillion BTU)	141	84	90	900	154	231	3	62	181	164	2,010		Total from EIA 1991 Energy Outlook. Splits based on American Paper Institute Data. N.Cent, S.Cent,and Mtn/Pac split 50/50. to sub regions.
Regional Distribution (Trillion BTU)													
BulkOil	75	70	96	139	99	159	21	25	100	24	808		See Oil Tables for substitutable split detail.
Gas-Industrial	83	198	462	869	1,248	3,045	905	134	609	156	7,100		Total gas sales to industrial.
Coal-Other	7	52	292	377	460	146	150	206	85	18	1,708		All coal ex coking.
Total Bulk	165	320	850	1,385	1,807	3,350	1,076	365	794	198	9,616		
Unique Oil	83	220	369	845	1,031	3,469	338	235	665	174	7,429		See Oil Tables for substitutable split detail.
Purch Electricity	93	160	336	707	760	465	373	102	246	216	3,212		Some in bulk market, not in daily competition with fuel.
Coal-Coke Plants	0	29	426	121	453	0	0	38	0	0	1,067		Coking coal used directly in process.
Renewable	141	84	90	900	154	231	184	62	181	164	2,010		Most in bulk market, not in daily competition with other fuel.
Gas-Lease & Pit Fuel	0	1	16	23	13	862	66	91	24	0	1,072		In bulk market, not in competition with other fuel.
Total Special	317	494	1,237	2,596	2,411	5,027	961	528	1,116	554	14,790		
Total TBTU	482	814	2,087	3,981	4,218	8,377	2,037	893	1,910	752	24,406		

Note: EIA -- Energy Information Agency, U.S. Department of Energy agent and also provides energy to the process. Natural gas may make inroads into this market primarily driven by environmental considerations but currently coal has an inherent advantage.

Electricity: Electricity is primarily used for motors, although there is some use for metal melting, heat treating, drying, and other applications. In new non-motor applications, interfuel competition is intense. However, on a day-to-day basis, existing electricity use does not face significant competition from other fuels.

Renewable/Other: Renewable/other energy consumption is predominantly waste fuel in the paper industry as well as noncommercial fuels used to generate electricity (e.g., municipal solid waste, hydroelectric power, etc.).

These fuels are consumed in unique circumstances and are not in competition with other fuels on a day-to-day basis.

Figure 4-6 illustrates the relationship of the fuels tabulated in Table 4-5 for the total U.S. As the chart shows, most of the fuel reported in the industrial sector is for applications in the "specialty" categories with less than 40 percent of the total in the bulk oil, natural gas, and steam coal categories.

Natural Gas Dominates Fuel Switching Market

Oil for bulk use, natural gas (except feedstock and lease and plant uses), and coal used in boilers are in day-to-day competition in existing fuel switchable facilities to supply energy services to end users. Prices for these competing energy forms cannot get significantly out of line with each other without causing fuel switching. On a continental U.S. basis, gas accounts for 74 percent, coal for 18 percent, and oil for 8 percent of the competitive bulk fuel market. Natural gas currently dominates the switchable market. Figure 4-7 illustrates the current relationship between these three competing fuels on a regional basis as reported in the EIA data sources. As the chart shows, gas is the major bulk fuel in the market in all regions except New England. However the addition of new pipeline capacity could significantly alter the fuel mix in the future in the New England region. The Southwest Central region, with its high concentration of energy intensive industries, accounts for over 40 percent of all industrial gas use.

The 1988 MECS survey published data on fuel switching capability by Census Region. The data for the total United States are summarized in Table 4-6.

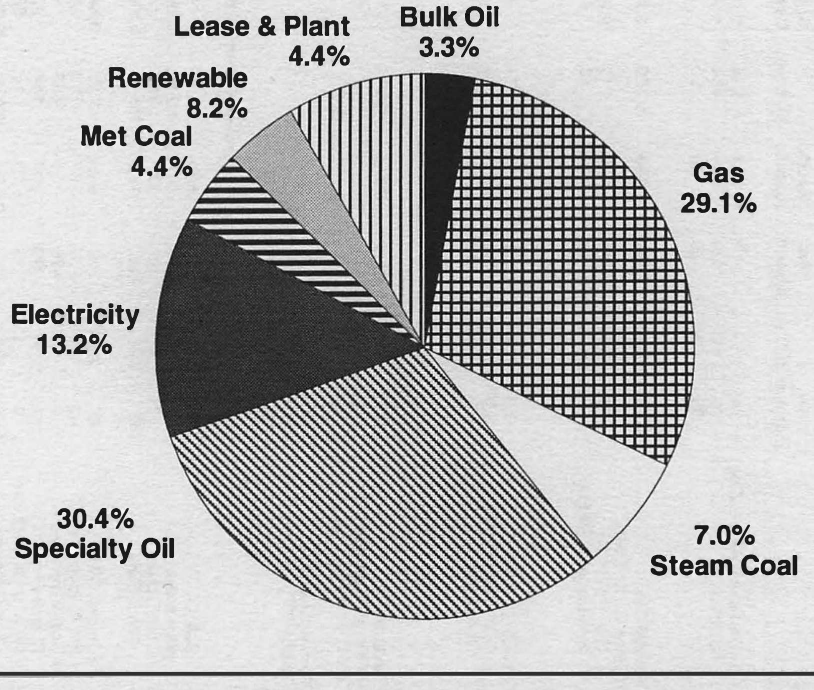


Figure 4-6. U.S. 1990 Industrial Fuel Use (24 Quadrillion BTU).

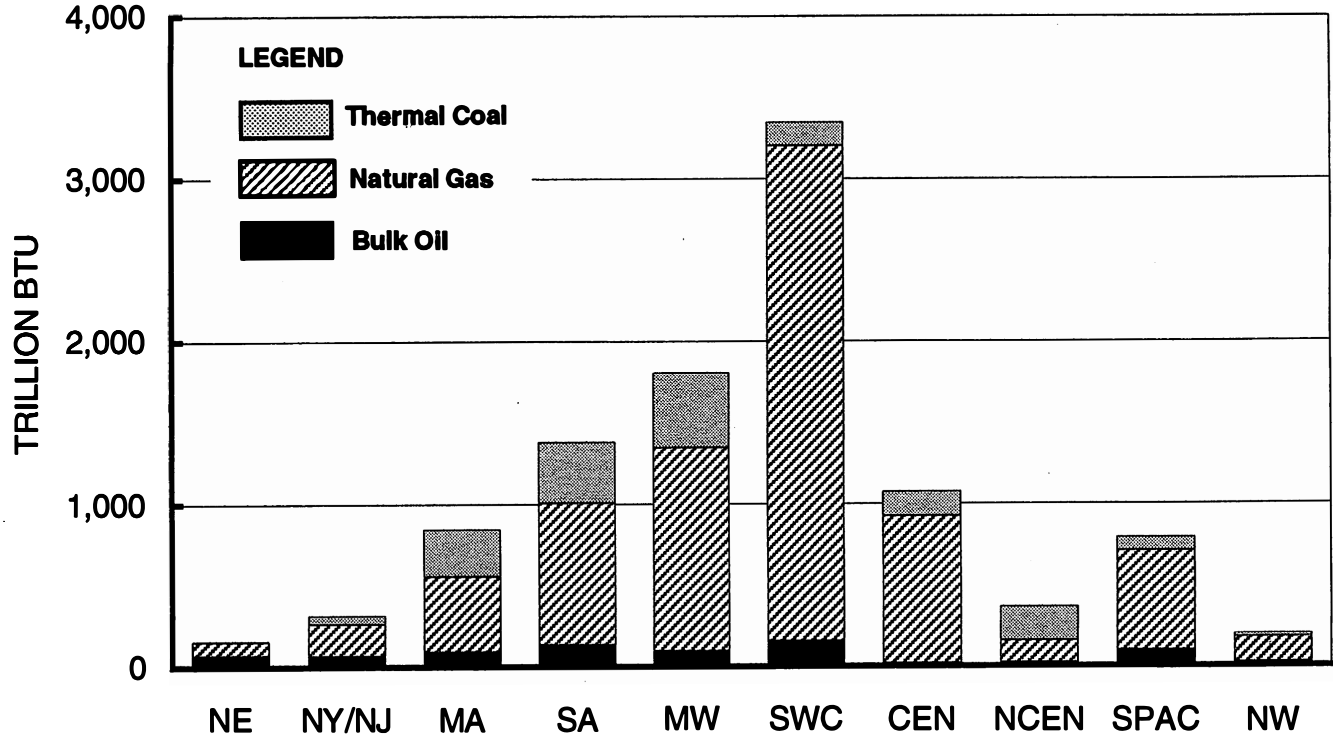


Figure 4-7. 1990 Industrial Bulk Fuel Use by Region.

The survey indicated that the capability to switch the fuel increment consumed above minimum to natural gas ranged from about 65 percent for coal and coke to 93 percent for LPG. While the time to switch varies, in all cases more than half of the load could be switched to gas in less than a day. If this load could all be captured, gas demand could be increased on the order of 1 trillion cubic feet (TCF) per year with most of the increase used to displace coal and coke.

The major threat to gas consumption is substitution by oil with about 90 percent of the capability to switch from natural gas in the LPG, distillate, and residual fuel oil categories. Since 1988, industrial oil and coal use have declined

TABLE 4-6

MANUFACTURING FUEL-SWITCHING CAPABILITY 1988

Type of Energy	Actual Consumption	Minimum Consumption	Maximum Consumption
Electricity Receipts (Million kWH)	728,168	716,905	771,426
Natural Gas (Billion cubic feet)	5,141	3,133	5,840
Distillate Fuel Oil (Thousand barrels)	36,766	27,712	244,855
Residual Fuel Oil (Thousand barrels)	90,413	43,647	265,080
Coal and Coke (Thousand short tons)	89,968	64,179	96,225
LPG (Million Gallons)	1,226	646	10,441

SOURCE: DOE/EIA-0515(88).

while gas has increased, suggesting continued penetration of gas into energy markets. However, when industrial gas prices rise above oil prices, there is evidence that switching does occur fairly rapidly. The NPC model projections that were presented in Table 4-1 and discussed in detail in Chapter Eight result in a similar environment in the future with no fuel switching away from gas and gas capturing most of the industrial growth market.

FACTORS THAT DRIVE INDUSTRIAL GAS DEMAND—OPPORTUNITIES

Cogeneration Markets are Expected to Grow

Many industrial processes use steam and also require power. In an electric utility, steam is typically used to power a turbine to produce electricity and is condensed following the turbines with cooling water. The combination of the two needs, power production and steam requirements, are synergistic. Where the two needs exist together, a system can be designed that produces power and steam at significantly lower total energy input than the sum of the inputs needed to produce the same power and steam in separate facilities. The production of power at locations where the steam is needed as well is called cogeneration.

Cogeneration systems are basically of three types; boiler steam turbine, combustion turbine with waste heat recovery steam generator, and combined-cycle. Each type of system has its own unique operating characteristics and produces a different ratio of power to steam. Until recently, the most common industrial cogeneration system was the boiler steam turbine type. This arrangement yields a relatively low power-to-steam ratio and a relatively large steam demand is needed to generate significant amounts of power. These systems are very common in energy intensive industries.

Combustion turbines produce a higher power-to-steam ratio than boiler systems. A combined-cycle facility adds power generation after the waste heat steam generator of the combustion turbine to further increase power generation. These types of systems have not been as prevalent in industry but have been used in special situations in major energy intensive industries such as petroleum refining. Over the last several years, significant improvements in turbine technology and reliability have resulted in making combustion turbines a viable option in a wider range of applications.

Non-utility electricity generation has grown rapidly over the past several years turning around the declining trend of the 1970s. Much of this growth is a result of growth in cogeneration systems. The significant efficiency advantage of cogeneration over conventional power production facilities should allow cogeneration to remain an attractive growth market for natural gas as new industrial facilities are constructed or existing installations are replaced.

Gas Demand Could be Increased by Extending Gas Service to Non-Gas Users

An increased market could be achieved for gas by extending gas service to facilities that currently do not have natural gas available. The 1988 MECS data from the fuel switching survey indicate a minimum oil consumption level of about 200 MB/D (400 billion cubic feet gas equivalent). While data do not exist on the location and size of these installations, some are probably very small consumers and distant from gas delivery facilities. The survey indicated that about half of the residual oil potential substitution lies in the Northeast, which has historically been short of natural gas delivery capability. As delivery systems are expanded, industrial customers are likely to switch to gas if the service can be provided economically. Key factors to gain this market will be the cost of the natural gas hook-up and the cost of the delivered natural gas. While small in the context of the total market, extension of gas service provides an opportunity for market growth.

Gas Demand Could be Increased by Reducing the Time Gas is Not Available to Interruptible Customers

Firm service is more costly than interruptible service and during peak periods, interruptible customers are interrupted if available capacity is required for firm customers. Since many industrial processes are critical and require constant operation, interruptible customers have responded to the threat of interruption by installing alternative fuel capability. With alternative fuel capability installed, interruptible customers utilize the most economic fuel. While warm winters have generally kept interruptions at a low level over the past several years, industrial customers protect themselves against interruption by having alternative fuel on-site entering into the winter. Many gas utilities and public service commissions require that a viable alternative fuel capability be demonstrated before interruptible service is provided. Even if no interruptions occur, it is probable that some of this fuel is consumed for economic or operational reasons. The MECS survey data indicate that the equivalent of about 300 billion cubic feet of gas was consumed in 1988 displacing oil. With the continued move towards deregulation of the natural gas system, there may be opportunities to reduce the duration of potential interruptions to multiple fuel users. As long as the improved service can be provided at a competitive price, firm service options would increase gas use.

New Technology Developments are Likely to Open New Gas Markets

Gas competes very well in the industrial sector and is the dominant fuel for steam and process heat applications. Nevertheless, there are opportunities to increase the market for natural gas through the development and commercialization of new and improved technologies particularly as new industries and processes emerge. Areas of opportunity include displacing fuels such as coal or coke in response to environmental pressures, use of gas for waste processing/waste minimization, and development of new gas technologies to compete in process heating and drying markets which are now dominated by electricity and other fuels. Capturing these opportunities will require continued research and development on improved gas-based technologies targeted at increasing productivity, product quality, process yields, and efficiency while meeting increasingly stringent emissions regulations. It is expected the major competitor to natural gas in the new technology application area will be electricity. Estimates of the size of these potential new markets vary, but each is important and it is critical that natural gas technology development continue if gas is to remain competitive. Additional discussion of technology issues is presented in Chapter Seven.

FACTORS THAT DRIVE INDUSTRIAL GAS DEMAND—ISSUES

Gas Substitution for Coal or Nonconventional Fuels in Existing Facilities Not Likely to Be Significant

Providing process heat or steam using non-oil and -gas fuels, such as coal or biomass, requires significantly more complex and costly combustion equipment. These fuels tend to be lower cost on a BTU basis than oil and gas with the decision to build a facility based on a tradeoff between fuel and operating costs and investment. The MECS survey indicated a market in the range of 650 billion cubic feet for gas against coal and coke if gas consumption could be maximized. Over the past several years, gas prices, in particular, have generally been below the levels anticipated when many of these facilities were constructed. There have been several reports of electric utilities using natural gas to substitute for coal during periods of low gas prices. This spot switching probably happens in the industrial sector as well, although delivered coal and coke prices are generally lower than gas. In addition, if gas prices remain stable or do not increase significantly, some industrial users may find it attractive to substitute gas for coal or other non oil fuel to reduce the relatively high operating and maintenance costs associated with the combustion of these fuels and to secure potentially valuable environmental credits as a result of the lower emissions resulting from natural gas combustion. Industrial coal demand data suggest that while gas substitution is possible, it has not occurred to any great extent as yet. Given mainstream oil, gas, and coal price projections, gas substitution for coal or nonconventional fuels in existing facilities is not likely to be significant.

Cogeneration Growth Limited By Available Sites and Will Not Always Increase Total Natural Gas Demand

Cogeneration is not a new concept and has been in use since the industrial revolution. However, changes in the regulatory environment making it easier and more attractive to sell electricity to the utility grid coupled with the improvements in gas turbine technology have significantly improved the economics of cogeneration projects. Within the industrial sector, the power from cogeneration facilities is not always produced in the form of electricity but is often used directly to provide power for compressors, pumps, and other facilities. Data are available on electricity production from non-utility generators, however, data on the amount of cogeneration used to produce power directly for use in industrial applications are lacking.

The potential market for cogeneration technologies is dependent on the availability of sites with a steam outlet. The higher power-to-steam ratios of modern cogeneration systems should allow economic cogeneration projects at sites that were previously unattractive. Since cogeneration is a more efficient method of producing needed steam and power services than producing them individually, new projects do not necessarily increase natural gas demand. In replacement situations, a new cogeneration system is often much more efficient than the boilers being replaced such that the addition of the power portion of the cycle may not result in any net fuel increase to the facility. In new installations, the natural gas demand for a cogeneration system is higher than for a boiler-only facility but obviates the need for new electric utility generation that might be gas based. Although overall load may not always increase from cogeneration, the market is very important since natural gas has a competitive advantage in both existing and new markets and offers customers an option for lowering their total energy costs.

Major Threat to Industrial Gas Markets is Substitution By Other Fuels in Multiple Fuel Capable Facilities

Natural gas has been and is expected to continue to be the fossil fuel of choice in the industrial sector. However, the market is not guaranteed. Natural gas will have to remain competitively priced and reliable to maintain the industrial market. While the recent wellhead prices of natural gas have been at near historic lows, the delivered price of gas to industrial customers varies considerably.

The July 1992 *Natural Gas Monthly* reports that April 1992 industrial natural gas prices in the continental U.S. ranged from a high of about \$5.25/million BTU in New York to a low of \$1.45/million BTU in Louisiana. Ten states reported average prices in excess of \$4.00/million BTU with only Texas, Oklahoma, and Louisiana having prices below \$2.00. These data cover sales by regulated pipelines and distributors which amounted to about 30 percent of the industrial natural gas consumption. This class of gas industrial customers is most likely to consist of smaller users of natural gas. Generally the economics of gas transportation are not clearly favorable to smaller users of natural gas.

Price data are not collected for the remaining 70 percent of industrial demand. Although the gas is transported through pipeline/distribution systems, prices are unknown to the transporters (who report sales prices) since ownership of the gas is never taken. While data do not exist, the significant shift to industrial customer purchasing and transporting separately over the past several years gives a strong indication that the actual cost of delivered gas for industrial transportation customers is significantly below that reported for sales customers.

With the current wide range in industrial natural gas delivered prices, some markets will be at risk if wellhead gas prices rise or alternative fuel costs fall. Loads serviced by local distribution companies could be particularly at risk if their fuel switchable loads have rate structures that do not allow prices to remain competitive with alternate fuels. The 1988 MECS data show that over 2 TCF of industrial gas demand could be switched to other fuels if gas became uneconomic, most of it very quickly. The existence of this large switchable market sets a competitive restraint on potential gas price increases.

Offset Provisions of the Clean Air Act and Stringent Environmental Permitting Requirements Favor Electricity

Environmental requirements for new and modified facilities have become and will likely continue to be more stringent. Most recently, the Clean Air Act Amendments of 1990 provide a mechanism whereby environmental offsets must be obtained in certain non-compliance areas before new facilities can be built or existing facilities renovated. Even though gas is clearly the cleanest of all fossil fuels, industrial customers may find it more attractive to use electricity which has no emissions at the site than to obtain the offsets necessary to increase natural gas consumption. Gas demand will be particularly at risk in ozone nonattainment areas where there is a greater than one for one NOx offset required. As environmental requirements continue to tighten, increased pressure will be placed on industrial gas customers to reduce all on-site fuel consumption including natural gas.

Changing Nature of Natural Gas Business Could Make Gas Purchasing Very Complex

The move towards deregulation of the gas transmission system and the unbundling of services has made gas purchasing more complex and uncertain, particularly until the transition is completed. The increased complexity of purchasing gas is a cost incurred by the users. Small industrial consumers may find the system unwieldy and could choose to purchase and burn other fuels if the gas purchasing and uncertainty issues are not dealt with in a timely manner. This issue is dealt with in detail in Volume IV, Transmission and Storage. Volume IV includes specific recommendations for reducing complexity and standardizing the process for purchasing and transporting natural gas.

FACTORS FAVORING INCREASED PENETRATION

Environmental Concerns Generally Favor Natural Gas Over Other Fossil Fuels

Title I of the 1990 Clean Air Act Amendments requires that all new or modified major NOx sources in ozone nonattainment areas undergo new source review, install "lowest achievable emission rate" controls, and purchase or find NOx offsets for the NOx emitted. These standards will apply on all new installations emitting greater than 25 tons of NOx per year. This means gas boilers using greater than 400,000 MCF per year and higher temperature gas processes using as little as 40,000 MCF per year could be affected. It should be noted that "lowest achievable emission rate" controls are those technologies that are technically feasible with no consideration given to cost. This will make installation or modification of large gas-using equipment much more expensive from both a capital and operating standpoint, and could discourage development in affected areas.

However, environmental policy could provide incentives for conversions, since industrial facilities can opt into affected unit status and receive allowances that could be sold if SO2 emissions are cut. Obviously, the impact of this factor will depend on the allowance price. For example, an industrial boiler fired by residual fuel oil with one percent sulfur will emit roughly one pound of SO2 per million BTU, and the gain from switching to gas will be $0.05 per million BTU for every increase of $100 per ton in the allowance price. If the allowance price were $400 per ton, gas could sell for $0.20 per million BTU more than fuel oil, everything else equal, and still be competitive. The advantage relative to fuel oil with two percent sulfur would be twice as large, but the fuel oil price would be lower, so the break-even gas price would be lower as well. Also in some instances, industrial facilities may be able to capture valuable allowances available for trading by switching to natural gas from other fuels. The value of the incentive will vary significantly by industry and region.

Advent of Transportation Market has Allowed Gas to Compete in the Industrial Sector with Less Regulatory Intervention

The deregulation of wellhead gas prices and the advent of a natural gas transportation market has resulted in an industrial market where end-user sales of natural gas have become a smaller and smaller share of the industrial gas demand. Today, less than 30 percent of the industrial market is served by pipeline and distributor sales of gas versus virtually 100 percent only a few years ago. This market change has effectively moved most industrial gas consumption out of a regulated price environment at the wellhead into a competitive world. This market change should allow gas to compete more efficiently on a day-to-day basis in its largest market. While competition does not always result in increased market share, the move of the industrial sector from a regulated to a price-competitive market has to be viewed as a favorable trend for future gas demand.

CONCLUSIONS AND RECOMMENDATIONS

The potential size and growth opportunities for natural gas in the industrial market will largely be determined by factors such as industrial output mix and growth, which are outside of gas industry control. As shown in the NPC Reference Cases, the industrial market could grow considerably or shrink depending on future trends in these parameters. Nevertheless, regardless of the size of the future potential market there are a number of important considerations that should be recognized and opportunities that must be taken advantage of if gas is to maintain and potentially increase its share in the industrial market.

The Industrial Market Must Not Be Taken for Granted

Natural gas has always enjoyed a high market share in the industrial sector and is the fossil fuel of choice. However, the energy market is becoming more complex and increasingly competitive. In order for gas to maintain and potentially increase its market share in the industrial sector, gas must provide a better value to the customer than other fuel choices. This value includes not only the delivered fuel cost, but other factors as well. Distributors, pipelines, producers, and regulators all have a role to play in keeping gas competitive. This activity requires not only efforts to keep the price of natural gas competitive with other fuels but includes activities to enhance the value of gas to the customer such as technology development and deployment.

Reliability Provides a Value to the Customer

Focus group results conducted as part of this study (see Volume V for Focus Group details) showed that natural gas is perceived as less reliable than other fuels. While this may or may not be reality, reliability provides value to the customer. The industrial sector has alternatives to natural gas use and the gas industry needs to develop innovative ways to improve reliability without damaging natural gas's competitive position. The concept that "the gas industry is willing to provide the level of service the customer is willing to pay for" does nothing to enhance the value of gas to the consumer nor increase demand.

Capitalize on the Environmental Advantages of Natural Gas

Natural gas is the cleanest burning of all fossil fuels and there may be innovative ways to grow the industrial market for gas by capitalizing on its environmental advantage. The gas industry generally views this advantage as yielding a price premium for gas which does little if anything to improve the natural gas market share. With the emerging, more complex world of environmental offsets and emissions trading, the gas industry may be able to enhance the value of gas to its customers by helping them understand and take advantage of various credits that may be realized by increasing gas use.

Focus Efforts on Technology Development and Commercialization

New technology continues to penetrate the industrial sector rapidly not only in energy using equipment but also in improved processes to produce goods of higher quality more efficiently. The gas industry needs to focus its attention on how gas can help its customers be more competitive in their markets. This may require increased expenditures by the industry for technology development and commercialization. Further discussion of technology and funding appears in Chapter Seven.

THE REGIONS

Natural gas markets for the industrial sector vary widely by geographic area. Summaries of key factors in these markets, discussed in detail in the Regional Reports performed as part of the Demand and Distribution Task Group activities, are discussed below.

Region One: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont

Region One has historically been and will continue to be a non-energy intensive region.

This means that the region does not consume as much energy per capita as the U.S. average. However, the residential and commercial sectors' energy consumption, due to large heating requirements, are much higher than other regions. Energy consumption in the region's heavy industry has declined over the past 20 years, and has remained fairly steady over the past decade. With 5.2 percent of the nation's population, New England consumed 6.4 percent of the nation's residential requirements in 1990, but only 1.6 percent of the nation's industrial energy requirements.

According to the Energy Information Administration's *State Energy Data Report Consumption Estimates 1960-1990*, overall gas consumption in the industrial sector of Region One has been growing at an average rate of approximately 3.6 percent per year over the past decade, even though average annual growth in total regional industrial sector energy consumption was only 0.1 percent from 1980-1990. Coal consumption increased at a rate of 4.6 percent, while oil consumption declined at a rate of 1.9 percent during the last ten years. Oil was still the dominant fuel in New England's 1990 industrial sector, however, with 43.3 percent of the fuel mix. Electricity followed with 24.7 percent, natural gas accounted for 22.4 percent, hydroelectricity for 3.5 percent, and coal for only 2.1 percent of industrial fuel consumption in Region One in 1990.

In comparison, 1990 U.S. industrial sector energy consumption was almost equally represented by natural gas and oil, with 37.1 percent and 36.4 percent of the fuel mix, respectively. Electrically accounted for 14.1 percent of industrial consumption, coal for 12.1 percent, and hydroelectricity for only 0.1 percent.

Therefore, although industrial energy consumption in Region One is not anticipated to grow significantly in total, there is still potential for the share of natural gas consumed to increase further and to displace oil. In order for natural gas to achieve a similar market share in Region One to the entire United States (assuming level regional consumption patterns), natural gas consumption by the New England industrial sector would have to increase by approximately 55-60 trillion BTU, or 15 percent over 1990 levels, over the next decade.

Region Two: New York and New Jersey

Although New York and New Jersey account for approximately 10.3 percent of the nation's population, they only consumed 7.2 percent of the nation's energy in 1990. Industrial energy consumption, in particular, was proportionately low, accounting for only 3.8 percent of total U.S. industrial sector energy consumption in 1990. While Region Two historically was not highly industrialized, it did consume over 6 percent of the nation's industrial energy in 1970. Heavy industry has, therefore, declined significantly over the last 20 years.

According to the Energy Information Administration's *State Energy Data Report Consumption Estimates, 1960-1990*, natural gas consumption in the industrial sector of Region Two has been growing at an average rate of approximately 0.9 percent per year over the past decade, although total regional industrial sector consumption declined at an average rate of 2.9 percent. During the same period, coal consumption declined at a rate of 4.8 percent per year, and oil consumption declined 4.6 percent per year. Oil was still the dominant fuel in the industrial sector of Region Two, however, with 48.4 percent of the fuel mix in 1990. Natural gas followed with a 22.7 percent share, electricity with 18.4 percent, and coal with 10.3 percent of industrial fuel consumption in 1990.

By comparison, 1990 U.S. industrial sector energy consumption was almost equally represented by natural gas and oil, with 37.1 percent and 36.4 percent of the fuel mix, respectively. Electricity accounted for 14.1 percent of industrial consumption, coal for 12.1 percent and hydroelectricity for only 0.1 percent.

Region Three: Delaware, Pennsylvania, Maryland, Virginia, West Virginia, and District of Columbia

The forecast for industrial production for the states located in Region Three show steady but not robust manufacturing output growth over the 1992-96 period of slightly less than 3 percent per year. This growth coupled with occasional fuel switching from oil and coal to natural gas will probably be sufficient to offset decreases from the closure of aging, uncompetitive plants which tend to be the heavier gas users.

Market share of natural gas for industrial process applications in the region is expected to increase with respect to oil and coal, and decrease with respect to electricity.

Overall, market share for natural gas in industrial process applications is expected to gradually decrease over the five-year planning horizon as the effects of the 1990 Clean Air Act Amendments under Title I come into play.

There are some marketing opportunities for natural gas associated with the Clean Air Act. Industrial customers may switch to natural gas from coal and oil as a means of generating NOx offsets in ozone nonattainment areas for internal use as well as to sell to other industrial customers. In addition, large industrial customers may convert their coal boilers to natural gas as a means of generating SO2 allowances that can be sold to electric utilities on the open market. Other opportunities include gas-fired incineration of air toxics and volatile organic compounds, natural gas air conditioning, and conversion of fork lifts and industrial truck fleets to natural gas. Conversely, final federal and state regulations relating to the Clean Air Act may make the installation of large gas-using equipment more expensive from both a capital and operating standpoint and potentially discourage some development of industrial gas usage.

More stringent regulations on oil storage tanks will provide opportunities for natural gas.

Region Four: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee

Region Four, though accounting for 15 percent of the nation's industrial economic output, accounts for only 10.5 percent of the industrial gas use. This is a result of the particular mix of industries in the region.

From 1979 to 1989, the region's industrial gas use declined 0.5 percent per year while industrial output rose 3.5 percent per year. The reasons are (1) conservation and (2) slow or no growth in the more gas intensive industrial sectors.

Much of the easy conservation in the region has been accomplished. Thus gas consumption is anticipated to grow at least half as fast as industrial output, even though much of the industrial growth will be in less gas intensive industries.

The biggest growth opportunity in the industrial sector in Region Four is expected to be cogeneration.

Region Five: Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin

Energy consumption by Region Five's industrial sector has steadily declined since 1980. Reduced demand for products of the region's steel and automotive industries has led to reduced energy needs.

Electricity and oil are expected to be the fastest growing industrial energy sources. Increased use of robotics and electrification of the region's durable goods manufacturing plants have led to increases in electric demand. Natural gas is expected to maintain its niche in clean burning applications, especially in chemicals industry, where the "dirty" burn of oil and coal prohibit their use. Gas has environmentally attractive qualities which include the absence of residue when it is burned.

Coal demand in Region Five is the largest in the country. The main reason for coal's dominance is the nearby and relatively inexpensive supply of the fuel. Much of the coal is used for coking in the production of steel and in industrial boilers.

Industrial cogeneration in the region is 12 percent of the national total. Hard times for the region's durable goods manufacturers have put large capital investment projects like cogeneration on hold. Currently coal and "other" are the largest cogenerating fuels in Region Five. However, by 1995, gas is expected to replace "other" as the second largest fuel used.

Region Six: Arkansas, Louisiana, Oklahoma, Texas, and New Mexico

In Region Six, Texas and Oklahoma dominate the gas market, accounting for 85 percent of gas consumption in the region.

In 1991, gas delivered to consumers in the region totaled 5.4 TCF. (This does not include lease, plant, and pipeline fuel.) Of this amount, 3 TCF was for industrial uses, mostly refineries and petrochemical plants. Texas and Louisiana industrials consume 1.8 and 0.9 TCF, respectively.

Cogeneration has been a major source of growth in the region's industrial gas demand and is expected to remain significant in the future. However, the growth of refining and petrochemical industries in the region may be limited by foreign competition and stringent air quality regulations. Also, domestic ammonia production, which uses natural gas as a feedstock, is expected to continue its decline.

Industrial gas consumption in the region is expected to increase to 3.5 TCF by 1995 and then decrease to 3.3 TCF by 2000.

Region Seven: Iowa, Kansas, Missouri, and Nebraska

Natural gas is used in the industrial sector both as a feedstock and as a fuel for direct heat, steam, and power generation. Petroleum fuels dominate the market for industrial fuel and power in Region Seven, followed closely by natural gas. Given the availability of transportation facilities, if gas prices continue to be relatively attractive, gas consumption could potentially increase displacing oil in dual-fueled boilers. Environmental policy may provide incentives for conversion, since industrial facilities can opt into affected unit status and receive allowances that could be sold if SO2 emissions are cut.

The region uses approximately 100 trillion BTU of coal in industrial applications, and the bulk of the coal consumption occurs in the states of Iowa and Missouri. The two factors that tend to limit gas penetration in coal markets are the existence of long-term coal contracts with relatively stable price terms from nearby coal-producing areas and the concern over reliability of gas supply.

For the region, despite high industrial gas demand growth rates, total gas consumption for industrial cogeneration is not likely to be substantial, given the current low level of demand. Estimates indicate that the region's gas demand for industrial cogeneration on a net basis, is expected to be around 7 billion cubic feet by the year 2000. The region's total gas consumption for industrial applications is expected to increase at an annual rate of 3 percent over the next decade.

Region Eight: Colorado, Utah, Wyoming, Montana, North Dakota, and South Dakota

Region Eight's gas consumption is dominated by the residential and commercial sectors. The industrial sector accounted for only approximately 29 percent of all gas consumed in the region and only 9.2 percent of the total employment in the region. The region's industrial sector is characterized as one of low energy consumption with a heavy emphasis on service-oriented applications.

Although the overall energy consumption in the industrial sector in Region Eight is rather small, natural gas has been and will likely to continue to be the fuel of choice in this sector. Currently, the majority of industrial customers are utilizing natural gas, and as a result, opportunities for additional penetration by natural gas are minimal. The real focus must be on preserving the traditional markets for natural gas while exploring new opportunities.

In reviewing marketing opportunities in the industrial sector, the use of gas-fired cogeneration appears to be the most significant. The obstacle in developing this market is being able to deliver a flexible yet economically attractive and reliable natural gas service to these new customers.

Region Nine: California, Arizona, and Nevada

The industrial sector of Region Nine is a diverse and changing market. Currently, the industrial sector accounts for 17 percent of all primary energy used in Region Nine and gas captures approximately 44 percent of the region's industrial energy requirement, nearly 10 percent higher than the national average. Oil, electricity, and coal provide the remaining 36 percent, 15 percent, and 5 percent, respectively of Region Nine's industrial energy needs. Improved access by industrial end users to competitively priced gas supplies, new interstate pipeline capacity additions and increased pressure on industrial users to burn clean fuels, has positioned gas to be the dominant fuel in the industrial sector.

Over 90 percent of Region Nine's industrial energy demand is within California. Process heating applications are the primary end use among the state's top energy consuming industries of oil production, refining, paper, primary metals, and chemicals. Mining operations in Arizona and Nevada account for almost half (45 percent) of those two state's industrial gas demand.

The largest gas consumption application in California, and Region Nine, is cogeneration. There are currently over 4,000 megawatts of installed gas-fired cogeneration capacity in the region, with California having over 93 percent of the total.

Unique to Region Nine are the large, energy-intensive enhanced oil recovery (EOR) operations located in central California. Gas provides some 82 percent of the EOR market's energy needs. A number of large gas-fired cogeneration installations serve the EOR market and they account for approximately 46 percent of the EOR market's gas energy use.

The industrial sector of Region Nine does not represent a major growth potential for gas demand. California's industrial gas demand is expected to grow by only 11 percent from 1991 to 2010. There is a well-established pattern of migration of heavy, energy-intensive industries out of the region. The trend reflects the high cost of doing business, an explicit and implicit preference for "clean" industries and a variety of regulatory burdens. The transition within California is nearly complete, except for the petroleum refining industry which is not expected to grow. Arizona and Nevada have a relatively small industrial base with opportunities for gas demand growth mostly limited to cogeneration potential in commercial applications.

Region Ten: Idaho, Washington, and Oregon

Region Ten's industrial sector is the most electric intensive in the nation. The low price of electricity has attracted industries that can only produce their products with large amounts of electrical power.

Coal use in the region is the lowest in the country, accounting for less than 1 percent of the national demand. Industries in this region generally use natural gas and residual oil for process steam applications.

The fuel demand is currently split between oil, electricity, and natural gas. The demand for natural gas is expected to decline slightly in the near-term and then grow moderately through 2010.

Cogeneration is not prevalent in Region Ten since the region has the lowest electricity prices in the nation.

Chapter Five

The Potential For Increasing the Use of Natural Gas in Electric Generation

The potential for increased use of natural gas to generate electricity has attracted considerable attention in the natural gas and electric industries, and among government officials, including regulators. This chapter reviews the recent history of gas use in electric generation and summarizes the Demand and Distribution Task Group's findings and conclusions concerning the potential for increased gas use in electric generation.[1] It also provides recommendations for dealing with obstacles that need to be addressed as natural gas plays a larger role in providing the energy needed to generate electricity.

Particular attention has been focused on the potential for natural gas in electric generation because:

- Demand for electricity has been growing and appears likely to continue growing more rapidly than the direct use of coal, oil, or natural gas.[2]
- Electric generation accounts for a large and growing share of U.S. energy demand. Energy used by traditional electric utilities accounted for 36.7 percent of all the energy consumed in the United States in 1991, up from 26.7 percent in 1973 and 32.3 percent in 1980.[3]
- Natural gas for the generation of electricity has important environmental advantages over coal and oil, and nuclear and coal-fired generation have faced declining interest or acceptability in many regions.
- Newer gas-fired generating units, particularly combined-cycle units, are more efficient,[4] generally have lower capital costs and lower non-fuel operating costs, and can be built faster and in smaller economic sizes than coal-fired units.

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[1] "Electric generation" as the term is used in this chapter includes generation by traditional electric utilities and independent power producers. Cogeneration and self-generation of electricity are covered in the commercial and industrial chapters of this report. This chapter does include some historical data on cogeneration and self-generation merely to show the relative importance of these activities in satisfying the nation's total demand for electricity.

[2] According to DOE-EIA data, during the period from 1981 to 1991, U.S. use of electricity grew nearly 29 percent while the consumption of oil increased by 2.5 percent, gas increased by 0.3 percent, and coal increased by 10 percent.

[3] Data source: U.S. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(92/03), March 1992, Table 2.1, page 23, Table 2.2, page 25 and Table 2.6, page 36. According to EEI data, traditional electric utilities accounted for 92.3 percent of electric generation in 1990, while non-utility generators, including cogenerators, small power producers and independent power producers accounted for 7.7 percent (see Table 5-3, below). Comparable data for 1991 are not yet available.

[4] More kilowatt hours of electricity output per BTU of energy input.

In summary: electric generation is an important potential market for natural gas; gas will face strong competition and must overcome a number of obstacles in this market; but, natural gas will be competitive and the obstacles can be overcome largely through actions by organizations in the gas industry.

This chapter:

- Summarizes the role of natural gas in electric generation in recent years
- Identifies the potential future demand for natural gas in electric generation and identifies the potential opportunities for increased gas use
- Identifies developments that have held down gas demand, changes that are underway, and obstacles to increased gas use that will need to be addressed
- Recommends actions that can be taken to help assure that natural gas plays a larger role in electric generation.

RECENT HISTORY OF THE ROLE OF GAS AND OTHER ENERGY SOURCES IN ELECTRIC GENERATION

The role of natural gas in supplying energy for electric generation has changed substantially during the past 20 years. This section of the report provides data on the role of gas and other energy sources in electric generation and points out that non-utility electric generation is playing an increasing role in supplying the nation's demands for electricity.

Percentage Share of Electric Generation by Gas and Other Energy Sources: Traditional Electric Utilities

Table 5-1 shows the changing percentage shares of electric utilities' net kilowatt hours (kwh) generated by gas and other energy sources during 1972 (the peak year for gas use in electric generation), 1980, 1985, 1990, and 1991. When viewing this table, it is useful to keep in mind that the total kwh generated by electric utilities grew from 1,750 billion kwh to 2,823 billion kwh in the 19 years from 1972 to 1991, an increase of 61 percent, or an average of 2.7 percent per year.

In summary, Table 5-1 shows that:

- The natural gas share of energy used by electric utilities declined sharply from the early 1970s—due largely to market distortions and high gas prices in the late 1970s and early 1980s caused principally by federal and state policies and regulations. The Fuel Use Act, now largely repealed, prohibited use of natural gas in some existing facilities and prohibited building new gas-fired electric generation facilities.
- The coal share increased substantially as a result of new coal-fired units built during the 1970s and 1980s.

TABLE 5-1

PERCENTAGE SHARE OF ELECTRIC UTILITIES' GENERATION BY ENERGY SOURCE*

Year	Natural Gas	Coal	Petroleum	Nuclear	Hydro	Other	Total
1972	21.5%	44.1%	15.6%	3.1%	15.6%	.1%	100%
1980	15.1%	50.8%	10.8%	11.0%	12.1%	.2%	100%
1985	11.8%	56.8%	4.1%	15.5%	11.4%	.4%	100%
1990	9.4%	55.5%	4.2%	20.6%	10.0%	.4%	100%
1991	9.4%	54.9%	4.0%	21.7%	9.8%	.4%	100%

* This table shows only traditional electric utilities and does not include generation by non-utility generators, i.e., independent power producers and commercial and industrial cogenerators.

SOURCE: U.S. Energy Information Administration, *Monthly Energy Review*, May 1992, DOE/EIA-0035(92/05), Table 7-1, p. 91; and *Annual Energy Review 1991*, DOE/EIA-0384(91), June 1992, Table 92, p. 211.

TABLE 5-2

ENERGY USED BY ELECTRIC UTILITIES

Year	Gas (TCF)	Coal (Million Tons)	Petroleum (Million Barrels)	Quadrillion BTU Gas	Coal	Petroleum	Nuclear	Hydro
1972	3.98	352	497	4.08	7.81	3.10	.58	2.83
1980	3.68	569	420	3.81	12.12	2.63	2.74	3.09
1985	3.04	694	173	3.16	14.54	1.09	4.15	3.33
1990	2.79	774	196	2.88	16.19	1.25	6.16	2.91
1991	2.79	772	185	2.88	16.07	1.18	6.54	3.05

SOURCE: U.S. Energy Information Administration, *Monthly Energy Review*, May 1992, DOE/EIA-0035(95/05), Table 7-3, p.95 and Table 2-6, p.33; *Annual Energy Review 1991*, June 1992, DOE/EIA-0384(91), Tables 94 and 95, pp. 215 and 217.

- The petroleum share declined very sharply and remains low.[5]
- The nuclear share increased rapidly but is now leveling off since no new plants have been ordered since 1974 and only two new plants are projected to come on-line by 2000. Otherwise, nuclear generation can increase only if the availability of existing nuclear units is improved. The nuclear share is likely to fall in the years ahead as availability declines and older plants are retired at or before the end of their operating licenses. Attachment #1 to this chapter lists operating nuclear plants in the United States according to the year in which the operating license for the plant expires.
- The hydro power share has been declining steadily—in percentage terms—since most available large U.S. hydro sites have already been developed.

Energy Used by Electric Utilities

Table 5-2 shows the quantities of natural gas, coal, and petroleum used by electric utilities during 1972, 1980, 1985, 1990, and 1991. The peak year for natural gas use in electric generation was 1972.

Quantities of Natural Gas, Coal, and Petroleum Used by Non-Utility Generators

Data on the rapidly growing non-utility electric generation are not as complete as data on traditional electric utilities. However, both the Edison Electric Institute (EEI) and the Energy Information Administration (EIA) have conducted surveys and issued recent reports.

Non-utility generators (NUGs) include independent power producers (IPPs) that construct facilities for the production of electricity that is sold on a wholesale basis to traditional electric utilities, and commercial and industrial cogenerators that produce both electricity and steam or heat that can be used for other purposes. Electricity in excess of the needs of commercial or industrial cogenerators is sold to an electric utility.

EEI Data on Non-Utility Electric Generation: 1986-1990

Table 5-3 shows the growth in non-utility generation and contrasts non-utility generation with that of the traditional electric utility generators. Note that, except for the following table, data on cogenerators are included in the commercial and industrial chapters. The cogeneration data are included in Table 5-3 only to show

[5] Not shown in Table 5-1 is the sharp increase in oil usage by electric utilities from 1985 to 1986 when Saudi Arabia sharply increased its oil production and world oil prices declined sharply—a strong reminder that (a) oil prices continue to be affected by cartel actions to manage production levels and (b) oil use by utilities could increase again if its delivered price is less than competing energy sources.

TABLE 5-3

MILLION MEGAWATT HOURS OF ELECTRICITY GENERATION

	Non-Utility				
Year	Cogenerators	Small Power Producers	Other Non-Utility Producers	Total NUGs	Traditional Elec. Util. Producers
1986	88.4	14.5	9.0	112.0	2,487.3
1987	118.4	18.5	9.7	146.6	2,572.1
1988	140.4	22.1	11.8	174.3	2,704.3
1989	157.0	30.8	13.1	200.9	2,784.3
1990	180.8	37.2	14.8	232.8	2,807.1
Each segment as percent of total:					
1986	3.4%	.5%	.3%	4.3%	95.7%
1990	5.9%	1.2%	.4%	7.7%	92.3%

SOURCE: Edison Electric Institute, *1990 Capacity and Generation of Non-Utility Sources of Energy*, December 1991.

the relative importance of cogeneration in supplying the nation's electricity demands.

EIA Data on Non-Utility Electric Generation: 1989-1990

Table 5-4 shows the breakdown by energy source for the electricity generated by non-utility power producers in 1989 and 1990. Note that the amount of generation is about 7 percent less than reported by EEI (summarized immediately above). The EIA report on which Table 5-4 is based is limited to producers with installed capacity of 5 or more megawatts, which may explain part of the difference.

OPPORTUNITIES FOR INCREASED USE OF NATURAL GAS IN ELECTRIC GENERATION

The potential markets for increased use of natural gas in electric generation include both traditional electric utilities, which supplied about 92.3 percent of the electricity used in the United States in 1990, and non-utility generators, which supplied 7.7 percent. The potential for increased use of gas by cogenerators, which currently make up a large share of non-utility generation, is covered in the commercial and industrial chapters of this report.

This section will discuss:

- The range of potential future demand for increased gas use as shown in two scenarios developed by the NPC
- Types of generating facilities where additional natural gas can be used
- The wide variation from case-to-case in the potential for increased gas use
- Key developments affecting the potential for increased use of gas in electric generation.

In general, there are four potential ways (in addition to cogeneration) that natural gas can play a larger role in supplying energy used in electric generation:

- Running existing gas-fired generating units more often (i.e., at higher capacity factors)
- Adding gas-burning capacity to existing oil- or coal-fired generating units (e.g., to gain fuel flexibility or meet environmental requirements)
- Repowering existing generating units (coal, oil, or nuclear), possibly increasing capacity of the unit at the same time
- Building new base-load, intermediate-load (cycling) or peak-load generating

units (by traditional electric utility or an independent power producer).

The question of whether any one of the above steps is necessary or advantageous to an electric generating company depends on a number of factors, including the generating capacity now available, expected growth in demand for electricity in the region, the condition of existing generating units, expected fuel prices, environmental requirements, and alternatives available.

As explained in more detail later, a decision to choose gas or an alternative depends on many factors that vary widely among sites, type of generating unit, potential applications, technologies, companies, regions, distance from fuel sources, and fuel transportation alternatives and costs. Those making fuel choice decisions for utilities or IPPs and those who wish to sell gas or provide transportation services to utilities and IPPs will have to understand factors affecting decisions on a case-by-case basis to make wise investment and marketing choices, rather than rely on model outputs.

Potential Gas Demand for Natural Gas for Electric Generation as Shown in Two Scenarios Developed by the NPC

The NPC Model Reference Cases are based on two fundamentally different scenarios for U.S. energy supply, demand, and prices for the period through 2010,[6] and were developed during the NPC Natural Gas Study. The Cases were developed as an attempt to show two different potential energy futures. It should be recognized that the model outputs for the two scenarios are merely the result of the input assumptions and neither Case is offered as a "forecast." In summary:

- Reference Case 1 contemplates U.S. energy demand growing from 82 quadrillion BTU (QBTU) in 1991 to 100 QBTU in 2010. It assumes economic growth averaging 2.4 percent per year, continuation of energy efficiency improvements, and crude oil prices[7] growing 1 percent per year in real terms (to $29 per barrel in 1990 dollars by 2010). It also assumes that electricity demand will grow by 1.5 percent per year from 1990 to 2000 and by 1.8 percent per year from 2001 to 2010, averaging 1.62 percent per year over the entire period.
- Reference Case 2 contemplates U.S. energy demand growing from 82 QBTU in 1991 to 88 QBTU by 2010. It assumes economic growth averaging 2.0 percent per year, increased energy efficiency, and crude oil prices of $20 per barrel in 1990 dollars by 2010. It also assumes electricity demand will grow 1.1 percent per year from 1990 to 2000, and by 1.5 percent from 2001 to 2010, averaging 1.3 percent per year over the entire period.

[6] The underlying scenarios, the assumptions, and the model outputs are described in more detail elsewhere. Specifically, a general description of the model and scenarios appears in Chapter Two of Volume I—the Summary Report of the Natural Gas Study. Additional information on the model and the assumptions used for the two scenarios is provided in Volume VI. A more detailed discussion of assumptions driving the model outputs with respect to natural gas demand appears in Chapter Eight of this volume.

[7] U.S. refiners acquisition cost of crude oil (RACC).

TABLE 5-4

MILLION MEGAWATT HOURS OF ELECTRICITY GENERATION

Year	Natural Gas	Petroleum	Coal	Hydro	Wood	Other	Total
1989	86.2	5.9	30.3	5.9	27.5	31.3	**187.1**
1990	99.1	5.4	30.9	6.2	30.7	42.9	**215.2**

SOURCE: U.S. Energy Information Administration, "Non-Utility Power Producers," by Lawrence Prete, Janet Gordon and Betty Williams, *Electric Power Monthly*, April 1992, pp. 1-18, Table FE1.

Model Outputs With Respect to Potential Gas Demand for Electric Generation

Table 5-5 shows the potential growth in gas demand for electric generation[8] in the lower-48 states *based on the assumptions used for the NPC scenarios.* The table also shows potential growth in gas demand for electric generation as shown in the Gas Research Institute's (GRI) "1993 Baseline," issued in August 1992, and the Energy Information Administration's "Reference Case," published in January 1992. Each source uses different input assumptions and different models to make calculations.

Key Input Assumptions That Determine NPC Model Outputs With Respect to Gas Demand for Electric Generation

Inputs to the NPC model included many assumptions that determine the outputs from the model under the two scenarios, including the above numbers on potential for gas in electric generation. Most of the assumptions affecting the model outputs with respect to use of natural gas in electric generation are explained in Chapter Eight. The various assumptions are listed in Attachment #2 to this chapter, along with the page numbers in Chapter Eight where the discussion of the assumptions can be found. The most important assumptions driving the model outputs with respect to need for new generating capacity and the gas share of energy used for electric generation are:

- Economic growth (and attendant factors affecting residential, commercial and industrial demand for energy).
- Demand for electricity.
- Delivered prices of gas, coal, and oil for electric generation, including fuel transportation costs.
- Capital costs for coal-fired and gas-fired generating units.
- "Floors" assumed for gas share of new generating unit market. This refers to assumptions that certain shares of new generation will be gas-fired regardless of the economics of gas vs. other energy sources (e.g., that all fossil-fueled generation projected for New England, New York, and New Jersey through the year 2010 will be gas- or oil-fired).
- Repowering of certain amounts of generating capacity, and that natural gas or oil will be the fuel used for the repowered facilities.
- "Institutional" constraints. These are judgments incorporated in the model concerning such factors as the lead-time that would be required to build coal-fired generating units, opposition to building coal-fired units in some regions, and the potential that electric utilities will be more willing after the year 2000 than before to

[8] Includes traditional electric utilities and independent power producers only. Gas used in cogeneration and self-generation of electricity by commercial and industrial organizations are shown in chapters covering those sectors.

TABLE 5-5

PROJECTIONS OF GAS DEMAND FOR ELECTRIC GENERATION (Trillions of Cubic Feet)

		Actual 1991	2000	2010
NPC	Reference Case 1	2.8	3.7	5.2
	Reference Case 2	2.8	3.1	4.8
GRI	1993 Baseline*	2.9	3.1	4.2
EIA	1992 Reference*	2.9	4.5	5.7

* Both GRI and EIA show other cases, with different input assumptions, that show higher and lower estimates of future gas demand for electric generation.

take the financial risks associated with building generating units. Another "institutional" constraint is the assumption that electric utilities will add generating capacity in accordance with plans and projections for new generation capacity for the period from 1990 to 2000 published by North American Electric Reliability Council in 1991.

Use of the outputs from the NPC Reference Cases with respect to potential gas demand for electric generation should be preceded by a careful review and thorough understanding of the assumptions that drive the NPC model outputs.

Regional Analyses

The last section of this chapter includes analyses, prepared by Demand and Distribution Task Group regional teams, of the potential for increased use of gas in electric generation in each of the ten regions. These analyses present an alternative assessment—compared to the model outputs—of the need for new electric generating capacity and the role of gas in supplying energy for electric generation.

Types of Electric Generating Facilities Where Additional Natural Gas Might Be Used

There are a variety of potential opportunities for increased use of natural gas in electric generation. Organizations in the gas industry need to understand the different potential applications in order to market effectively to electric generating companies.

Existing Gas-Fired Generating Units

In some areas where gas use in electric generation was prevalent in the 1970s, some utilities built coal-fired and nuclear generating units and reduced the use of gas-fired units to comply with the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA). Some of these gas-fired units are mothballed and others are in use but operate at low load factors. These generating units could use additional gas when prices are low or when electricity demand increases to the point where they are needed because other available generating units are running at full capacity.

Existing Oil- Or Coal-Fired Units That Add Capability To Burn Gas

Some electric utilities are adding—or have the potential to add—gas burning capability in existing oil- or coal-fired steam generating units. Adding such capability—so the unit can run fully on gas or on a co-firing or reburn basis—would generally be done to permit meeting tighter environmental requirements, particularly to achieve reductions in sulfur dioxide and carbon dioxide emissions; provide an alternative fuel source as protection against supply interruptions or price increases for the primary fuel source; and/or increase the diversity of the utility's energy sources.

Repowering of Existing Generating Units

Some electric utilities are "repowering" existing generating units, or have the capability to do so. "Repowering" may involve a wide range of actions, including:

- Substitution of a new boiler (one that could burn gas, oil, or coal) for an existing boiler and continuing to use an existing steam turbine and generator
- Adding one or more new gas turbines that drive new generators and using the excess heat to make steam that would supply an existing steam turbine and generator (i.e., a combined-cycle configuration)
- Substituting an entirely new gas-fired combined-cycle facility (gas turbines, waste heat boiler, steam turbine, and generators).

Generally, distillate oil (#2) would be the back-up fuel for use in gas turbines, though environmental and energy facilities siting-board authorities in some states are imposing stringent restrictions on back-up fuel use.

Repowering often offers an attractive opportunity for electric generation since it uses an existing generating site and may:

- Involve less neighbor and community opposition as compared to a new site
- Take less time to obtain necessary permits
- May involve less cost—since land, some usable facilities (access to transmission

lines, water supplies, maintenance, etc.) and support services are already available.

New Base Load Generating Units

In some cases, new base load generating units may be needed to accommodate increased electricity demand or to replace units that must be retired.[9]

"Base load" refers to generating units that are kept on-line for long periods to serve electricity demand. They often run for weeks or months without being taken off-line, though they may be producing electricity at less than full capacity. New gas-fired combined cycle generating units are being built in some areas for this purpose. Such new base load units may be built by electric utilities or by independent power producers.

New Intermediate or "Cycling" Units

In some cases, expected electricity demand may indicate the need for new generating units that "cycle" or provide electricity for what is sometimes called "intermediate" load. These units are started when demand for electricity increases and shut down when it decreases. For example, they are most likely to be started when demand increases in the morning hours of a weekday and shut down late in the afternoon. They may be run on weekends when weather is quite hot or cold, but are less likely to be run during the spring and fall.

New gas-fired combined-cycle units are being built for this purpose. As electricity demand increases or existing base-load units are shut down, these units may become base load units. Such units may also be built by electric utilities or by independent power producers.

New Peaking Units

In some cases, expected electricity demand may indicate the need for new generating capacity that is run only to serve "peak" demand—perhaps only a few hours on days with high loads, only a few days per year, or when there is a shortage of capacity due to unexpected outages of base load or cycling units.

Gas- or oil-fired turbines are commonly used for this purpose. Peaking units may be the only type of capacity needed by some utilities, particularly those that have built significant amounts of base load capacity in the past and are experiencing low load growth.

Gas- and oil-fired turbines initially built for peaking purposes may be constructed so that waste heat boilers and steam turbines can be added later, turning the facility into a combined-cycle configuration for use in serving cycling or base loads.

Peaking units may also be built by electric utilities or by independent power producers.

Co-Generation and Self-Generation

Gas-fired electric generating units may be built by commercial or industrial facilities in a cogeneration configuration or solely as electric generating units to provide needed power (perhaps with the sale of excess power to an electric utility). As indicated earlier, cogeneration and self-generation by commercial or industrial facilities are covered in other chapters of this report.

Repowering Uncompleted or Retired Nuclear Generating Units

Nuclear generating units that were not completed or have been retired offer another potential opportunity for increased gas use. In such cases, gas turbines and waste heat boilers, arranged in a combined-cycle configuration, could be used to drive steam turbines and generators originally built for the nuclear plants.

Wide Variation from Site to Site in the Potential for Gas Use

Current and potential gas demand varies widely among the regions of the country for many reasons such as distance from gas supply sources, availability and cost of existing transportation and distribution systems, and availability and cost of competing energy sources. In addition, the NPC has found that the opportunities for the use of gas and its relative eco-

[9] Relatively few utilities have scheduled retirements of existing generating units. Instead, if capacity is needed, necessary capital and maintenance work may be done to extend the life of the unit or it may be "repowered" as described above.

nomic favorability vary *widely* among sites, particular applications, and particular situations of the organizations that own or operate the facilities. In addition, perceptions as to future gas supply availability and prices have an important impact on choices among fuel sources made by electric generators.

Generalized analyses[10] of the relative economic advantages of gas vs. other fuel sources are valid only as indications of potential competitive position. Actual fuel choice and facility investment decisions must take site-specific factors into account. Because of the importance of site and application-specific factors, Attachment #3 to this chapter identifies many of the factors taken into account by an electric generator when making choices among energy sources for new facilities or the repowering of existing facilities.

Key Developments Affecting the Potential for Increased Use of Gas in Electric Generation

A number of developments in recent years have contributed to increased interest in relying more heavily on natural gas for electric generation.

Developments Important at the National Level

At the national or public policy level, key developments that tend to encourage increased use of gas include:

Clean Air Act requirements. Stringent restrictions have been imposed on emissions of sulfur dioxide, oxides of nitrogen, and particulates from new and existing generating units by the Clean Air Act (CAA), particularly as that Act was amended in 1990. Also, increasingly stringent state air quality requirements are being imposed as a part of state air quality implementation plans (SIPs) and at the same time states grant permits for modifications of generating units. In accordance with the "acid rain" provisions of the 1990 CAA amendments, electric utilities must reduce sulfur dioxide emissions by about 8 million tons nationwide (or approximately half of the level of sulfur dioxide emissions in 1985). These reductions will be achieved either by installing flue gas scrubbers, switching from high to lower sulfur coal, or using gas or low sulfur oil along with coal (referred to as "co-firing" or "reburning").

Concern about global climate change and "greenhouse gasses." Growing public concern about potential global climate changes and "greenhouse gasses" has led to increased interest in natural gas, which results in less emission of carbon dioxide (CO2) and, potentially, nitrogen oxides (NOx) than other fossil fuels.

Repeal of Fuel Use Act prohibitions. Prohibitions in the 1978 Powerplant and Industrial Fuel Use Act against using natural gas in existing industrial and electric generating facilities or building new gas-fired facilities have been substantially repealed. Those restrictions were based on a belief, now recognized as incorrect, that the nation was in danger of running out of natural gas.

Gas prices. Natural gas wellhead prices and oil prices have proven to be much lower than projected in the late 1970s when the Natural Gas Policy Act (NGPA) was passed. Even though prices have been low, supplies have been plentiful and the outlook is favorable for adequate long-term supplies and competitive prices.

Less risk of overruns. Gas-fired combined-cycle and combustion turbine units tend to have less risk of cost overruns that often occurred in the case of large coal and nuclear generating units in the 1980s. Gas-fired units have less risk of overruns because a large share of the total capital cost is in standard manufactured items that do not require much field assembly. The units tend to have shorter construction times, more standard components, and, often, prices arranged largely in advance with the manufacturer.

State "environmental externalities" requirements. 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,

[10] Generalized analyses are often based on "average" costs (i.e., averages of fuel cost, fuel transportation costs, capital costs, non-fuel operating and maintenance costs) that do not reflect site-specific variations that generally are critical when making fuel choice or capital investment decisions.

but "externality" requirements generally result in an advantage for natural gas compared to other fossil fuels, but a penalty compared to conservation and renewable energy sources.

Public opposition in some regions to coal-fired facilities. In some regions, opposition to the construction of new coal-fired facilities or the conversion of existing industrial or electric generating facilities to use coal have effectively prevented increased use of coal and given gas an advantage.

Declining expectations for nuclear power. Strong public opposition to nuclear power plants and concern about nuclear waste has reduced expectations as to the future contribution of nuclear power as a potential source of energy for electric generation.

Concern about reliance on imported oil. Concern about reliance on imported oil and "vulnerability" to oil supply disruption has continued to be the rationale cited by the Department of Energy and many special interest groups to support proposed actions that might have the effect of shifting energy use to domestic sources (such as natural gas, coal, or nuclear energy) or reducing energy requirements by improving efficiency of energy use.

Reduced concern about long-term adequacy of gas supplies and rapid increases in gas prices. Several developments have tended to reduce the concern among electric generators and regulators about the adequacy of long-term gas supplies or the possibility of sharp prices increases, including:

- Continuing adequacy (or excess) of gas supplies, gas-on-gas competition, and relatively low prices
- Continuing moderate prices for other fuels with which gas will compete, including coal and oil
- Studies by and for the U.S. Department of Energy and the National Petroleum Council showing higher estimates of the U.S. natural gas resource base
- Continuing replacement of production (i.e., little or no decline in reserve to production ratios) even with lower levels of U.S. gas drilling activity
- Improvements in technology for finding and producing natural gas and lowering of estimates of cost of replacing reserves
- Slower growth in the demand for gas than had been expected due to slow economic growth and to continuing improvements in energy efficiency, thus relieving some concerns about gas demand outstripping supply.

Changes in pipeline regulation. Changes in Federal Energy Regulatory Commission (FERC) regulation of interstate pipelines, including "open access" regulations and approval of additional pipeline capacity expansion projects has made gas more readily available in areas and to users not previously considering gas. The net impact of FERC Orders 636 and 636A, which call for the restructuring of interstate pipeline activities, is not yet clear, but the FERC's policy of encouraging competition is favorably regarded. The FERC's intent is apparently to lower the price of gas to customers who do not require service during peak periods. This may help electric generators that have access to and capability to use interruptible gas. However, firm transportation service may be more costly.

Developments Important at the Site or Facility Level

Some developments favoring increased natural gas more directly affect specific facilities or sites. Examples include:

High efficiency gas-fired turbines and combined-cycle generating facilities. Advances in gas-turbine technology and metals (particularly from aircraft engine technology) and the development of gas-fired combined-cycle generating units have made it possible to generate electricity with gas with substantially higher efficiency than is possible with commercially available coal-fired generating units.

Lower capital and non-fuel operating costs. Capital and non-fuel operating costs are lower for natural gas-fired generating units than for comparably sized coal-fired units.

Modularity. Gas-fired generating units, particularly in combined-cycle configurations, can be built as modules (one or two gas turbines, followed by a waste heat recovery boiler and steam turbine), making it easier to add generating capacity as electricity demand increases—as opposed to building a large increment of coal-fired capacity.

Shorter construction time. Gas-fired generating units can generally be built more quickly than coal-fired units.

Less neighbor, community, and "public interest group" opposition and potentially shorter permitting time. In many regions, gas-fired facilities tend to attract less opposition from neighbors, communities, and "public interest groups." Such lower opposition tends to translate into less opposition from media and political leaders and, potentially, to less delay for facility owners and developers in obtaining the dozens of permits that are usually required.

Lower emissions and less waste. Gas-fired facilities emit virtually no sulfur dioxide, much less carbon dioxide and potentially less nitrogen oxides than coal- and oil-fired facilities using the same amount of energy. Also, gas-fired facilities produce substantially less waste (e.g., ash, sludge from scrubbers) than coal- or oil-fired facilities.

Emergence and growth of independent power producers. IPPs that produce and sell power on a wholesale basis to electric utilities have tended to select natural gas more often than other fuels. The selection of gas over other fuels, particularly coal, is heavily affected by such factors as:

- Economic size of the facility (particularly for cogeneration)
- Likelihood that the facility will be built at a new generating site and thus the developer has the option of selecting a site near an adequate gas pipeline or other gas supply source
- Unlike a traditional electric utility, the IPP developer does not have the option of taking advantage of economics of building another unit at an existing site (which is important when coal is an option)
- The availability of sites close to gas pipelines
- Opposition in some regions where additional generation is needed to coal-fired facilities
- The likelihood that a NUG facility will be at a new site (not an existing generating site) and it is easier to obtain permits for a gas-fired facility
- Shorter construction time and other factors favoring gas listed earlier in this section.

Developments Tending to Retard the Demand for Electricity, New Generating Capacity, and Energy Needed for Generation

While the factors described above have contributed to a strong potential for increased use of gas in electric generation, other factors tend to retard growth in demand for electricity and the need for new generating capacity, thus holding down the size of the market for which natural gas will be competing. These factors include:

Slow economic growth. Electricity demand growth has tended to parallel economic growth more closely than has demand for primary energy sources such as oil, coal, and natural gas. The weak state of the U.S. economy during the past two years has undoubtedly contributed to slower growth in electricity demand.

Conservation and load management. Many electric utilities—particularly in the Northeast and on the West Coast—have undertaken ambitious Demand Side Management programs. These programs typically are designed to encourage customers to use less electricity or to use it more efficiently (i.e., "conservation") and, in some situations, to reduce peak demand (i.e., load management). These programs are spreading to other areas and are likely to have a major impact on the rate of growth in demand for electricity.

Integrated Resource Planning (IRP) requirements. Electric utilities in more than 30 states now must comply with some kind of requirement to develop "Integrated Resource Plans." IRP requirements are having a major impact in that they are encouraging adoption of energy efficiency, conservation, and load management activities ("demand-side") by electric utilities. Such demand-side activities reduce the rate of growth in overall demand and peak demand for electricity, the need for new generating capacity, and fuel to generate electricity. The impact of IRP requirements is likely to increase as such requirements spread to more states and utilities. (More details on electric utility IRP requirements are included in Attachment #4 to this chapter.)

Energy efficiency standards and regulations. Statutes and regulations adopted by the federal and state governments have stimulated energy conservation and greater efficiencies, such as standards for electrical appliances and for insulation. The cost-effectiveness of this approach is and will remain open to question but the impact is likely to include increased efforts to develop more energy efficient products.

Improvements in technology for conservation and energy efficiency. Improvements in technologies for energy conservation and energy efficiency, stimulated in the late 1970s by higher oil prices, have continued and expanded. Even though prices have moderated, technological improvements are continuing because of the stimulus provided by electric utility demand-side programs and federal and state energy efficiency standards and regulations. Electricity demand is being held down by products with improved energy efficiencies now on the market such as improved light bulbs and ballasts, variable speed motors, appliances, insulation, windows, doors, and other building materials.

Change to less energy-intensive U.S. industrial mix. The continuing trend in the United States toward a less energy-intensive mix of industrial activities is also tending to slow growth in demand for electricity.

Increasing output of existing generating facilities. Even when electric utilities are faced with the need for additional generating capacity, they often have options that may be less costly than building new generating capacity. These include capital and operating and maintenance (O&M) expenditures to extend the lives or increase the availability of existing facilities, and increasing generating capacity as a part of actions to repowering existing facilities. Utilities may also decide to buy power from other utilities that have excess capacity.

CHALLENGES THAT MUST BE OVERCOME AS THE ROLE OF NATURAL GAS IN ELECTRIC GENERATION INCREASES

While many important developments are working to increase interest in the use of natural gas in electric generation, important challenges must be overcome before the objective of substantially increasing the role of natural gas in electric generation can be fully realized. This section of the report outlines those challenges.

While many obstacles have been identified, the NPC has not found any obstacles that are not being or cannot be overcome. The obstacles could be overcome more quickly—for the benefit of electric and gas customers and the environment—through concerted effort by organizations in the gas and electric generation industries; local, state, and federal government agencies; and organizations representing environmental and consumer interests.

Adjusting to the Changing Structure of the Gas Industry and Changing Electric Generation Markets for Natural Gas

Changes in statutes,[11] regulations, and energy markets have had a major impact on the natural gas industry during the past 14 years and more changes are underway. As a result of the changes, many individuals and organizations in the gas industry have new roles and responsibilities, new markets, and new customers whose concerns, needs, and expectations must be understood.

The adjustment process is underway, but will have to be pursued aggressively by organizations in the gas industry if gas is to realize its market potential.

The information in this chapter is intended to help individuals and organizations that wish to improve their understanding of potential de-

[11] Including particularly the Natural Gas Policy Act (NGPA), The Powerplant and Industrial Fuel Use Act (PIFUA), and the Public Utility Regulatory Policy Act (PURPA), all passed in 1978 and all having important implications for gas demand.

mand for natural gas in electric generation. It also provides recommendations on ways to accelerate the adjustment process through actions by organizations in the gas industry and other parties.

Incomplete Gas Industry Understanding of Potential Markets in Electric Generation

Organizations in the gas industry that may wish to sell or transport natural gas to electric utilities may not understand electric utility decision processes or the factors affecting making fuel choices.[12] Some in the gas industry believe that electric utilities have a "coal bias" and/or favor selection of coal-fired facilities because they have higher capital cost and thus increase the utilities rate base. This view is sharply disputed by representatives of electric utilities who believe some in the gas industry are laboring under false impressions as to which factors are important in fuel choice decisions.[13] Because of incomplete understanding of electric generation markets and decision processes, economic analyses of fuel choice decisions now being prepared by organizations wishing to sell or transport gas to electric utilities may miss important considerations.

Further, the NPC Study Focus Groups revealed a strong view among electric generation executives, fuel buyers, and regulators that organizations in the gas industry need to be more aware of and responsive to potential customers' needs.

Attachments #3 and #4 to this chapter provide additional information, respectively, on factors (including site-specific factors) that are likely to affect fuel choice decisions and additional information on the electric generation industry such as key developments, planning processes, power pools, and "economic dispatch" of generating units.

[12] As indicated earlier in this report, major changes in regulation in the natural gas industry, particularly interstate pipelines, have changed roles. For example, gas producers who once sold only to pipelines, now have an opportunity to sell to end users.

[13] See Attachment #4.

Incomplete Electric Generation Industry Understanding of Potential for Using Gas

Electric generators may not be sufficiently familiar with the potential for using natural gas for electric generation. Use of natural gas by electric utilities has largely been confined to six states (Texas, Louisiana, Oklahoma, California, New York, and Florida). The practical effect is that electric generators do not have the same knowledge and familiarity with natural gas as they do with oil and coal. In some cases, this lack of familiarity undoubtedly contributes to the concerns and perceptions of electric generation. (These concerns and perceptions are discussed later in this chapter.)

Competition from Other Energy Sources

Natural gas has a number of advantages over other fossil fuels in electric generation markets. However, the NPC also found that gas will face stiff competition in electric generation markets from coal, oil, renewables and, in some regions, from excess nuclear and coal-fired generating capacity. These factors are discussed below.

Coal

Natural gas will face stiff competition from coal in large areas of the United States[14] because:

- Coal-fired generating units equipped with available pollution control equipment can meet existing environmental requirements
- Coal-fired generating units that can be located near coal-producing areas generally can obtain coal at prices below the national average delivered costs for coal (which includes higher transportation costs)

[14] From Arizona, Nevada, and Montana on the West; Canada on the North; Western New York, Pennsylvania, possibly Western parts of Maryland, Virginia, the Carolinas and Georgia, and Florida on the East (also, some coal-fired generation is still planned for Maryland, New Jersey, and Delaware); and the Gulf of Mexico on the South. Ground-breaking was recently announced for a 150-megawatt coal-fired generating unit in Massachusetts which, heretofore, had been considered unlikely to accept construction of any coal-burning facility.

- Coal prices have been going *down*, even in current dollar terms, particularly because of new technology and higher mine productivity. New contracts are being signed at prices lower than existing contracts and high sulfur coal prices are likely to continue falling in most areas
- Rail transport costs have been going down in real terms
- Generating plants with water delivery for coal can take advantage of competition among ship and barge owners or buy their own vessels to control ship and barge transportation rates
- Some organizations operating electric generating units prefer coal (or oil) because they can be stored on site:
  - Giving the electric generator the opportunity to optimize transportation arrangements and costs
  - Providing more "comfort" because the fuel supply (coal or oil) is on site and under the generator's control—compared to a pipeline connection to an offsite gas supply that is under someone else's control.
- Some states with indigenous high sulfur coal are concerned about the potential adverse economic impact of the loss of coal mining jobs and are strongly urging electric utilities to install scrubbers and continue use of high sulfur coal rather than switch to lower sulfur coal or gas.

In addition, some potential electric generation users of gas are concerned that there is greater uncertainty about future natural gas prices than about coal prices. They appear to be concerned about the adequacy of gas supplies and fear that gas prices will increase rapidly if shortfalls occur. Expectations that gas prices will rise much faster than prices for competing energy sources—whether correct or not—can, in economic evaluations, offset the economic benefits of the efficiency, capital and O&M cost and other economic advantages of gas.

Further, coal producers and transporters tend to have an excellent understanding of electric generation markets (their largest market, by far) and working relationships with electric generation customers. Coal producers and transporters have departments and staffs specializing in service to electric generators, and tailor contracts and service to the needs of their electric generation customers. Also, many coal contracts have clauses that invoke price reductions when bonafide offers exist for alternative supplies of comparable coal.

Oil

The electric utility industry has sharply reduced its use of oil since the high levels of the late 1970s, specifically from an average of 1.742 million barrels per day in 1978 to 506 thousand barrels per day in 1991. Some additional reductions can occur as electric utilities add gas-burning capability in existing oil-fired units or repower existing oil-fired units using gas. The potential for such actions depends heavily on the availability of gas transportation capacity, the cost of building additional gas transport capacity, utilities' perceptions of future gas prices (wellhead and delivered), and, potentially, environmental requirements. Some existing oil-fired generating units are too remote from pipelines to permit economical use of gas and probably will remain on oil.

A substantial amount of generating capacity has the capability to use either oil or natural gas. The choice as to fuel used actually depends on which fuel has the lowest delivered price on any given day, which, in turn, often depends on the availability of low cost interruptible gas transportation capacity. When delivered gas prices are lower than delivered oil prices (usually residual oil), gas is likely to be used. When delivered oil prices are lower, oil is likely to be used.

In addition, a substantial amount of oil-fired steam-generating capacity remains available for use in some regions if and when needed. When the incremental costs (which consist primarily of the delivered cost of the oil) are higher than other available generating units, these units tend to be used as "cycling" or intermediate load units. Oil-fired peaking units (turbines or internal combustion), which typically use #2 oil, generally are run (dispatched) only to serve peak electricity demand.

Renewables

Renewable energy sources for electric generation include hydro power, geothermal, solar, wind, and biomass. Hydro provided 9.8 percent of the energy used by electric utilities in 1991, and other renewables, combined, provided 0.4 percent. Relatively little expansion in hydro power is likely, but advances in technology may help other sources.

Natural gas will face competition from renewable energy sources because these energy sources (like conservation) have less adverse environmental impact than generation with gas or other fossil fuels. In addition, newly passed energy legislation provides valuable tax incentives for using renewable energy sources. Some utilities are deploying small increments of advanced renewable technologies to test their viability. This market is helping to lower production costs for these technologies and make them more competitive. In some states, electric utilities are being strongly encouraged to increase the share of renewables in their generation mix by aggressive environmental and public utility regulatory authorities, state siting boards, and state legislators.

Competition from Existing Generating Capacity in Areas with High Reserve Margins

Several important areas of the country with substantial nuclear and coal-fired capacity in place have very high reserve margins. In areas with high reserve margins, some coal-fired units are not run at full capacity. Power from these facilities and from nuclear facilities in high reserve areas is available to sell to other utilities at very low rates. In these areas, new gas-fired generation is unlikely to be more economical than buying power available from *existing* nuclear and coal-fired generating units.

Much of the nation's coal-fired capacity has been built since new source performance standards were put in place in the 1970s and will be largely unaffected by the "acid rain" provisions of 1990 Clean Air Act Amendments. These units could be affected by nitrogen oxide (NOx) requirements now being considered for some areas of the country. (Gas-fired plants may also be affected by new NOx requirements.) Much of the nuclear and coal-fired capacity in areas with very high reserve margins was built or committed to during periods when electricity demand was expected to grow more rapidly than has actually occurred.

Restrictions on the Use of Back-Up Fuels

In some states, regulators (usually environmental agencies or siting boards) have imposed limits on the use of back-up fuels for electric generating units—either by prohibiting use of a back-up fuel (e.g., in California), restricting the number of days, or sharply limiting the conditions (e.g., in Rhode Island) under which the gas-capable facility may be switched to its back-up fuel (usually #2 oil).

Such limitations can result in higher than necessary costs for both electric and gas customers. That is, they prevent electric utilities and LDCs from working together to share pipeline capacity and gas supplies in a way that would give an LDC's "core" customers priority access to gas supplies on very cold days, while allowing the generating unit to use its back-up fuel. If prevented from shifting to a back-up fuel in such situations, the electric generator with firm pipeline capacity would have to continue using gas. To satisfy its customers' peak demands, the LDC will often have to use a high cost "peak shaving" fuel (e.g., LNG or propane air), with the gas customers paying the required higher cost.

Such limitations also have the effect of increasing the cost of gas transportation facilities serving the region if optimization of load, such as that described above, is prevented.

In addition, if the pipeline capacity serving a region is limited, unnecessary prohibitions on the use of a back-up fuel may prevent a utility or power pool from dispatching—or even counting upon—an otherwise economical generating facility on very cold days.

Gas Industry Responsiveness to Customers

The National Petroleum Council has learned, and the NPC's Focus Group studies confirm, that organizations in the gas industry (producers, marketers, pipelines, and LDCs) are perceived as not having an adequate understanding of *their* downstream customers needs, concerns, and expectations and are not being sufficiently responsive to them. In short, they are perceived as not having a "customer-oriented culture."

The perceptions about gas industry attitudes towards customers appear to be due in part to major changes in regulation and a lack of marketing experience. Participants are still adjusting to their new roles and responsibilities in a more competitive era.

Changes in attitude appear to be occurring. Some potential electric generation customers that sought firm pipeline capacity in the past perceived a lack of interest by pipelines and LDCs in expanding pipeline capacity. Electric generators who are interested in gas use are seeking responses from pipelines and LDCs that indicate "if you want to use (or increase use) of gas, we will work with you and our other customers to find the most efficient, lowest reasonable cost way of delivering gas to you."

As indicated earlier, most past gas use for electric generation has occurred in six states. Gas and electric industry relationships have worked out in those cases and undoubtedly can work in other areas where there is a potential for increased gas use.

In the case of gas producers, some appear to have concluded that focus group and customer criticism is accurate and have undertaken efforts to improve their understanding of markets and their responsiveness to customer needs.

Electric Generators' Concerns, Perceptions, and Needs That the Gas Industry Will Have To Address

During the course of its activities, members of the Demand and Distribution Task Group learned a great deal about the concerns and perceptions of the electric generation industry concerning increased reliance on natural gas. This information was obtained through participation in the Task Group and from presentations by representatives from the electric generation industry, from the analysis or reports and studies from a variety of sources, and from reports from Focus Groups.

The concerns and perceptions of decision makers in the electric generation industry, whether accurate or not, will affect the potential for increased gas use and, therefore, must be evaluated and addressed by those who wish to increase the role of gas in providing energy for electric generation. Ten major concerns are described below.

Importance of Fuel Price Expectations

Expectations as to future fuel prices are particularly important in the electric generation industry when investment decisions are made that affect the amount and source of energy that will be needed in the future. The decision may, for example, involve the investments in energy conservation and other demand-side activities, in the purchase of electrical power from others, adding capability to use another fuel, or increasing generating capacity by building a new unit or repowering, extending the life, or increasing the availability of an existing unit.

Fuel price expectations affect the economic calculations that underlie the investment decisions. Depending upon the organization involved, the sources of information on which expectations are based may include highly sophisticated internal studies, consultant-provided information and analyses, commercially available or government published fuel price forecasts, and, perhaps, information obtained at random from general and trade press stories.

Regardless of the source, information on fuel price expectations has an important effect on electric generators' fuel choice and other investment decisions. When the decision involves a capital investment, the impact is likely to be long-lasting (e.g., the choice between a coal-fired or gas-fired generating unit).

Importance to Electric Generators of the Delivered Price of Fuel

Investment decisions, customers bills, and prudence of fuel buying. For most decisions that are affected by fuel price expectations, it is the *delivered* price of fuel that is of primary importance; i.e., the cost of fuel at the wellhead, mine, or refinery, plus the cost of transporting the fuel to the site of the generating unit. *Estimates* of the delivered price of fuel must be used in economic analyses of alternative investment decisions (including both demand- and supply-side investments). The *actual* delivered cost of fuel is the cost that electric customers see in their monthly bills, and it is the *actual* delivered cost that will be evaluated at some point (after the fact) by a utility commission to determine whether the electric utility has been prudent in its fuel procurement actions.

Economic dispatch. One important point where *a cost other than full delivered fuel cost* is used is when hour-by-hour, minute-by-minute decisions are made as to which generating units should be run (i.e., "dispatched") to serve the electric demands being made at the time. Electric utilities and the power pools in which they participate seek to dispatch—as electric demand increases and decreases—those generating units that will provide electricity at the lowest cost to customers; thus the term "*economic dispatch*."

The important factor for "economic dispatch" is the *incremental cost* of running a generating unit. In general, "incremental cost" refers to the difference in costs being incurred when a unit is being run vs. the costs when it is not being run. Incremental costs do not include, for example, fixed capital costs, O&M costs (such as wages and salaries of people who are needed whether or not a generating unit is run) or fixed fuel transportation costs. In the case of most generating units, fuel costs make up the overwhelming share of incremental costs. This explains why hydro and nuclear units tend to be dispatched ahead of fossil-fueled plants. The incremental cost of running a fossil-fueled plant often changes from day to day as fuel prices change. Generally, demand charges associated with natural gas would not be a part of incremental costs if they must be paid whether or not a gas-fired generating unit is being run to produce electricity.

Adequacy of Future Gas Supplies and Concern that Gas Prices Will Rise More Rapidly than Coal Prices

Despite market and technology developments and regulatory changes of the past 10 years, and recent information about the nation's natural gas reserve base and availability of imports, some potential electric generator users of gas are concerned that gas may not be available on a long-term basis for use in electric generation and/or that its price will increase more rapidly than coal prices. These concerns are the result of such developments as:

- Emphasis in the 1970s on reserve-to-production ratios as an indicator of potential future gas availability
- Federal government policies of the late 1970s and the Powerplant and Industrial Fuel Use Act of 1978 that restricted gas use in existing generating facilities and virtually prohibited building new gas-fired generating facilities
- Statements and forecasts made from a variety of sources that have suggested that gas demand would increase, supply would tighten, and prices would likely increase sharply in the mid-1990s
- Media attention focused on the decline from the 1981 peak in oil and gas exploratory drilling activity
- Actions in gas producing states to extend the role of "prorationing," which gives the appearance of cartel-like attempts to restrict production as a way of increasing prices.

Focus Group reports suggest that some LDCs and regulators are also concerned that significant increases in gas demand for electric generation may jeopardize supplies or contribute to price increases for residential and commercial customers who do not have readily available alternatives. Concerns such as these impede decisions to rely more on gas for electric generation.

Evaluation of Concerns About Future Gas Supplies and Prices

The NPC concludes that the electric generation industry should take considerable comfort with respect to the adequacy of future gas supplies from a variety of regulatory and market developments during the past 10 years, including:

- The demonstrated ability, during the past 15 years of the gas producing industry to maintain reserve to production ratios of 9 or more to 1, despite increased gas consumption and decreased drilling activities
- The technological advances in exploration and production

- The availability of competitively priced imported gas, primarily from Canada
- The findings of the Source and Supply Task Group concerning the U.S. natural gas resource base and productive capability. (See Volume II, which reports on the work of the Source and Supply Task Group.)

The NPC also concludes that concerns that natural gas will not continue to be priced competitively are misplaced. Natural gas markets are likely to continue being functioning, competitive commodity markets. Forces at work to keep gas prices in line with competing energy sources include:

- Direct competition with other gas in end-use markets (i.e., gas-on-gas competition).
- Pipeline-on-pipeline competition in regions served by two or more pipelines.
- Competition among LDCs and among end users with pipeline capacity or supplies excess to their needs *if* capacity reassignment measures work effectively and *if* pipelines allow LDCs and end users delivery point flexibility.
- Competition at the point of energy consumption with other energy sources and with conservation—as noted earlier.[15]
- Future gas prices will be affected by the supply and demand for gas and the supply, demand, and price of competing energy sources.
- Gas prices at the burnertip are effectively constrained by competition for markets in which end users have the capability to:
  - Switch among fuels (e.g., industrial and electric generation facilities that can switch among natural gas, oil, and/or coal) to get the lowest price, or
  - Dispatch electric generating facilities that have the lowest incremental (largely fuel) costs.

  In effect this means that delivered cost of gas to an end user is often constrained by marginal costs of competing fuels in the electric generation and industrial sectors.
- Gas for industrial and electric generation markets must be price competitive. Buyers for these organizations are sophisticated and effective in creating and taking advantage of competition among energy sources and fuel suppliers.
- While natural gas may have environmental advantages over other fossil energy sources, those advantages are taken into account in the price that gas can command in competitive markets. Gas does not get an additional premium because of environmental or other advantages. (However, some states have proposed "environmental externality" requirements that would give an advantage to gas over other fossil fuels.)
- The emergence of an active gas futures market, together with changes underway in regulation of gas transportation, have added and will continue to add "transparency" to the gas prices.
- The emergence of futures markets has also provided a way for producers, marketers, LDCs, and end users to reduce price risks.

Adequacy of Pipeline Capacity and Market Area Storage

In some regions, absent or inadequate pipeline capacity has been a major deterrent to increased gas use. Building of interconnections, and expansion of capacity into California and the Northeast appears to have relieved many concerns about pipeline capacity into major using areas. Major growth areas, such as Florida, appear to need additional capacity and more may be needed in the Northeast if substantial new gas-fired electric generating capacity is constructed, existing units repowered, or gas-burning capability is added to existing units.

[15] The relationship of delivered prices for fuels is an important (but not necessarily the controlling) factor in energy choices made by users. Other factors vary widely among energy users but generally include capital cost tradeoffs, site specific considerations such as availability and cost of transportation, public and political acceptance, regulatory requirements, and perceptions of future fuel availability and prices.

Additional market area storage is being constructed in some regions, though the Northeast (and particularly New England) has little or no storage because of high costs and physical limitations (geology) on availability of acceptable sites.

The Demand and Distribution Task Group notes that the Transmission and Storage Task Group has addressed these issues in detail and concluded that construction of additional pipeline capacity and storage is well within the financial capability of the industry. (See Volume IV for the findings of the Transmission and Storage Task Group.)

Questions do remain as to the availability of suitable sites for market area storage in some regions and the cost and allocation of cost for both existing and new pipeline capacity, a topic that is discussed in more detail below.

Potential for Short-Term Interruptions in the Delivery of Gas Supplies at Point of Use

Some potential electric generators are concerned about unexpected short-term interruption of gas supplies. More specifically the concerns are directed towards:

- Unexpected interruptions of gas supplies or transportation service (including firm service) due to unplanned outages of pipelines or compressors, and to well freeze-ups and
- Government (regulator) actions that may direct that available gas supplies, even when firm transportation has been contracted for, be reserved for core residential and commercial customers, for example, during periods of extremely cold weather.

These concerns about the potential for short-term interruptions or curtailments appear to come from:

- Memories of curtailments in the late 1970s (even though those were due to distortions introduced by wellhead price regulation) and in December 1989 (due to prolonged cold weather) and
- Perceptions that existing regulations require that core customers have priority for gas service when some users must be denied service.

The potential for interruption of gas deliveries makes it necessary to have an alternative fuel burning capability as a back-up. This increases costs.

Representatives of the electric generation industry have also expressed the view that the gas pipeline and LDC-owned systems do not seem to have:

- As much "redundancy" (to protect against interruptions) as is typical among electric utilities or
- As complete inter-company coordination of operational and contingency planning as is typical in the electric utility industry.

The gas pipeline segment of the gas industry points out that it has recognized the concern over curtailments and has acted to increase reliability through the construction of additional pipeline capacity, pipeline interconnections, and gas storage facilities. The Demand and Distribution Task Group notes that the Transmission and Storage Task Group has given considerable attention to reliability issues. (See Volume IV.)

Ability of Gas Pipelines and LDCs to Deliver Gas in the Volumes, Pressures, and Sharp Changes in Volumes Required for Newer Generating Units

Representatives of the electric generation industry have expressed the view that pipelines and LDCs in some regions, even with storage, line pack, and available compressor capacity, would need to upgrade pipeline systems significantly in order to meet electric generators' requirements. Peaking and combined-cycle generating units with gas turbines often require high gas pressures (350 pounds per square inch or above) and large volumes of gas, and must start up and shut down with little or no notice.

Such requirements are understood and routinely satisfied in regions with experience in using gas for electric generation. However, the concerns remain in other regions with less experience with gas use where there may be opportunities to increase the use of gas to generate electricity.

The Electric Power Research Institute (EPRI) recently issued a report based on the work of a team that has been studying the issue.[16] (The study team had an advisory committee consisting of representatives from electric utilities, independent power producers, local gas distribution companies, and gas pipelines.)

In addition:

- A study of similar issues is underway in New York state in the form of a cooperative effort between the New York Power Pool and the New York Gas Group.[17]
- A study and analysis effort is underway in New England involving electric generators now using or planning to use significant quantities of gas, LDCs, pipelines serving the region, and the New England Power Pool (NEPOOL). This effort is being supported financially by the EPRI.[18]

From an operational point of view, this issue has several important aspects:

Limited experience with using gas in electric generation in some regions. As shown in Table 5-6, six states have accounted for the overwhelming share of gas use by electric utilities. Other states have had limited experience with use of gas in electric generation and, where it was used, it was often on an interruptible basis.

High gas pressure requirements. Gas turbines, used for peak electric generation, and gas turbines used in combination with waste heat boilers and steam turbines in combined-cycle configurations have relatively high gas pressure requirements. Specifically, according to the EPRI report:[19]

- Combined and simple cycle gas turbines may require pressures of 400 pounds per

16 *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination*, Final Report, September 1992, prepared for the Electric Power Research Institute. Principal investigators were W. R. Hughes, Charles River Associates Incorporated; S. Thumb and J. Stamberg, Energy Ventures Analysis Incorporated; and J. Jensen, Jensen Associates Incorporated.

17 *Reliability of Gas Supply for Electric Generation, Phase I—Steady State Conditions*, Draft of October 4, 1991, New York Power Pool and New York Gas Group.

18 The Electric Power Research Institute is providing consultant assistance from Energy Ventures Analysis, Charles River Associates, and Jensen Associates.

19 Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination, op. cit., pp. 3-3, 4-4, and 4-5.

TABLE 5-6

GAS USE BY ELECTRIC UTILITIES

	1985		1990	
State	**Quantity (BCF)**	**% of U.S. Total**	**Quantity (BCF)**	**% of U.S. Total**
Texas	1,198	39.3%	1,007	36.2%
Louisiana	285	9.4%	269	9.7%
California	666	21.9%	456	16.4%
Oklahoma	201	6.6%	169	6.1%
New York	173	5.7%	223	8.0%
Florida	166	5.4%	188	6.8%
Subtotal	**2,688**	**88.3%**	**2,313**	**83.0%**
All others	356	11.7%	473	17.0%
Total	**3,044**	**100.0%**	**2,786**	**100.0%**

SOURCE: U.S. Energy Information Administration, *Natural Gas Annual 1990*, Volume 2, DOE/EIA-0131(90)/2, December 1991, Table 15 (pages 179 and 189).

square inch (psi) and above, compared to 100 psi and below for steam-electric units

- These requirements have implications for:
  - The design of pipelines and generating facilities
  - Locations selected for generating facilities; e.g., capability of an existing pipeline to serve the projected load, including other customers that are or would be served.

Short start-up times for some facilities. According to the EPRI report, "Modern combustion turbines can ramp up from start to full capacity in about 10 to 20 minutes and ramp down just as quickly."[20] Steam electric units have much longer ramp up times and lower pressure requirements, though steam electric units maintained in "spinning reserve" (i.e., unit is hot and connected to the grid but not taking load) ". . . can increase output . . . and reach full capacity in 2 to 4 hours."[21]

Large quantities of gas required compared to existing loads. The quantity of gas needed by large industrial and electric generating facilities may be very large compared to the total capacity of the pipeline or LDC providing the gas to the facility. For example, the EPRI report points out the following comparisons (approximate) of daily equivalent peak LDC and generating plant gas loads:[22]

	Million Cubic Feet per Day
Typical 36" pipeline	800
Washington Gas Light Company	550
Typical 16" pipeline	150
Brayton Point (MA) 430 mw gas conversion	120
Providence Gas Co. (serving Providence, RI)	100
Ocean State Power 470 mw combined cycle	100
Typical 12" pipeline	90

[20] Ibid, page 3-3.

[21] Ibid, page 3-6.

[22] Ibid, pages 2-9 and 2-10.

Wide fluctuation and quick changes in amount of gas needed. In addition to the high pressures and large quantities of gas required for electric generation, such uses are likely to require sharp changes and wide fluctuations in the quantity of gas taken at any time. Gas-fired generating units may be used in:

- *Base load generation*—which typically operates a large share of the time.
- *Intermediate or "cycling" load generation*—which typically operates during heavy demand periods of the day and week (perhaps from 8 a.m. to 4:30 p.m. on work days, depending upon the temperature and the air conditioning load).
- *Peak load generation*—which operates only at times of high demand, perhaps running for only the equivalent of 4 days per year.

Typically, electric generating units are started up and shut down (dispatched) as the demand for electricity dictates. Often the dispatching is computer controlled, with the choice of unit based on the incremental cost of running the unit ("economic dispatch"). The principal element of incremental cost is *incremental fuel cost.*

The important point is that gas-fired generating units—and, therefore, the quantities of natural gas required—vary widely from hour to hour, day to day, work day to weekend, season of the year. Furthermore, the extent to which a gas-fired generating unit will be called upon to produce electricity depends upon *other units available*—which varies from time to time because of both planned and *unplanned* outages.

In short, the quantity of gas required can be "0" at one minute and, depending upon the type and size of the gas-fired unit, at a rate of 100 million cubic feet of gas per day a short time later! In addition to their own needs, electric generators are concerned that gas service to residential and commercial customers might be impaired if pipeline facilities are not adequate to provide the volumes, pressures, and variability in volumes that are needed for the generating units, while also serving core gas customers.

Arrangements for coordinating the planning and dispatch of pipelines transportation. The electric generating industry, in many regions, is characterized by "power pools." Under power pool arrangements, all dispatchable electric generation is put under the operational control of a dispatching center controlled by the power pool—*not the company owning the generating equipment.*

In general, the lowest incremental cost generating units are run first—so that customer costs are kept down. Savings from such pool-managed economic dispatch of generating units are shared among the customers of the utility(ies) owning the generating units that are dispatched and the utility(ies) needing the electricity. This arrangement helps to keep costs down because individual utilities do not need to maintain back-up service for all their own customers.

Representatives of the electric generation industry have noted that there appear to be no comparable arrangements among natural gas pipeline companies for coordinated "dispatching" of pipeline capacity with the objective of reducing costs for customers.

Gas and electric industry coordination in regions not accustomed to using large quantities of gas for electric generation. In six states where gas has long been used in electric generation, arrangements have been worked out to handle operational coordination—including the wide swings in quantities of gas required, sudden changes and pressure requirements. Areas served by a combination utility having responsibility for providing both gas and electricity appear able to handle the needed coordination. In other cases, close coordination between gas and electric industries have handled the operational coordination.

Other than the analysis and coordination efforts cited earlier, work does not appear to be underway to assure that increased use of gas in electric generation in other regions with less experience in using gas for electric generation can be handled without jeopardizing service reliability.

Importance of Gas Transportation and the Cost of Gas Transportation

Pipeline transportation costs are a major portion of the total delivered cost of natural gas in many regions of the country. As indicated earlier, delivered cost of fuels—not just the wellhead or mine-mouth cost of fuel—are the important consideration for electric generators making choices among energy sources. Delivered fuel costs—i.e., for coal vs. natural gas and oil—are a particularly important consideration when a decision is being made to construct at a new site,[23] a new base, or intermediate load electric generating unit; add natural gas burning capability at an existing facility—for fuel flexibility or environmental compliance reasons; or repower an existing facility.

Current pipeline transportation costs and the perception that such costs may be significantly higher in the future can have a retarding effect on the potential for increased natural gas use in at least several ways:

Demand charges. Obtaining firm gas pipeline transportation service for LDCs, electric generators, or industrial users often requires signing long-term contracts with a commitment to pay demand charges for a 15 or 20 year period, whether or not gas is used up to the volume covered by the demand charges. While this is a perfectly reasonable way to assure that financing is available to pay for expanded transportation capacity, the existence of demand charges tends to cause concerns among electric generators in three ways:

- *High fixed commitment.* Demand charges represent a fixed commitment over a long period, well beyond any reliable projections of future energy market conditions and prices. In addition, rating agencies are showing increasing tendencies to consider long term contracts as liabilities to be taken into account in setting bond ratings. Thus, demand charges constitute a long-term risk that must be taken into account.
- *Potentially high unit cost when load factors are low.* The cost of the demand charge per unit of natural gas actually used can be high if the effective load factor (i.e., total share of contracted capacity that is represented by actual throughput) is low. This can occur easily in electric generation, where the quantities of gas needed is highly variable.

[23] As explained earlier in this chapter, considerations are different when an option is available to build a new generating unit at an *existing* site.

- *Straight fixed variable (SFV) rate design.* Concerns about demand charges tend to be greater in the case when rates are based on straight fixed variable rate design (as opposed to modified fixed variable) because a larger share of total costs is reflected in the demand charges, exacerbating the concerns listed above.

Distance from pipelines and storage that can provide quantities, pressures and variability needed. The cost of gas transportation will continue to depend heavily on the cost of building or upgrading the capacity to get gas to the end user's facility. Distance, terrain, environmentally sensitive areas (e.g., wetlands), historically important locations (e.g., archeological sites), and availability of or potential for storage near the end user's facility are, therefore, important considerations.

Potential for unexpected increases in gas transportation costs after investment commitments have been made for facilities that use gas. Some electric generators are concerned that gas transportation costs will increase significantly and unexpectedly after they have made substantial capital investments on the basis of lower expected transportation costs. Examples of this concern include:

- *Incremental vs. rolled-in rates.* The FERC's decision to approve incremental rates for pipeline transportation after the prospective gas user had made a substantial capital investment on the basis of an earlier FERC decision that transportation rates would be based on rolled-in costs.
- *Costs and charges resulting from "Restructuring" under Order 636.* The policy objectives of FERC Order 636 are generally perceived as contributing to competition in the gas industry and thus are regarded favorably by electric generators. However, some pending restructuring proposals have created concerns and added uncertainty about gas transportation costs. Proposals causing concern include those dealing with:
  - Allocation of "transition" costs (e.g., whether such costs would be allocated to new users of gas for electric generation)
  - Restrictions on receipt and delivery points that would make it difficult for electric generators to manage their gas supplies and transportation capacity
  - Tight tolerances and high penalties for variations in the volumes of gas used (electric generators have wide variations)
  - Imbalance penalties
  - Restrictions on the availability of secondary markets that reduce the ability of electric generators to sell gas supplies and/or transportation capacity to others when not needed because generating units are not running (an important need in order to help maintain high load factors and hold down unit cost of gas actually used)
  - Allocation of storage capacity among customers.
- *Other rate increases and design changes.* Rate increases due to actual costs of capacity expansion exceeding pipeline companies' estimates, the reallocation of pipeline or LDC costs from one customer class to another—to either reduce or increase the amount of cross-subsidies.

Potential for cross-subsidies. While FERC restructuring efforts are designed to increase competition, some portion of the pipeline delivery of gas for electric generation and, possibly, storage (if any) will remain a natural monopoly and be subject to regulation. Where such situations exist, some electric generators are concerned that LDCs, gas pipelines, or agencies regulating LDCs and pipelines may conclude that the large users, such as electric generators, should pick up a larger than proportionate share of the costs, in order to provide a cross-subsidy to "core" residential and commercial customers. Core customers and regulatory commissions may be concerned that cross-subsidies will flow in the opposite direction.

Burden of the long-term obligation to monitor pipeline and LDC rate cases. Since transportation rates and terms of contracts for transportation service can be changed by regulatory decisions (change in regulatory policy or regulatory agency approvals of pipeline proposals for changes in rates), electric generators must be prepared to take on the responsibility to monitor rate and regulatory proceedings affecting pipelines transporting the gas they use. There is no directly comparable requirement in the case of other energy sources.

Complexity of Buying and Transporting Gas Compared to Other Fuels

Except for those with extensive experience, electric generators seeking to use gas have indicated that arranging gas supplies and transportation and administering those arrangements is far more complex than arranging comparable quantities of coal or oil. The Transmission and Storage Task Group is aware of this problem and addresses it in Volume IV.

Gas Supply Contract Terms and Conditions

Perceptions have existed in some organizations (government and private sector) that long-term contracts are essential to increased use of gas in electric generation. The NPC has found that interest in long-term contracts varies widely among existing and potential electric generation users of gas, and that electric generators have strong interests in gas supply contract terms and conditions other than or in addition to length of contract. These include:

- Pricing terms and the basis for and frequency of price adjustments as markets for gas and competing fuels change
- Security of supply offered by the producer or marketer
- Willingness of the supplier to agree to variations in the amount of gas taken (which depends upon generating unit availability and need for its capacity which will vary according to electricity demand).

Due to these concerns, some electric generators (and their regulators) may prefer short-term contracts or spot purchases that track market-based prices, as discussed below.

Widely differing interests in long-term gas contracts. Views and interests in long-term contracts depend upon one's experiences, needs, responsibilities, and perceptions of future energy markets. The following examples help illustrate the point.

- *Independent power producers* often seek long-term fuel and transportation contracts because they often use project financing and the financial institution involved in the detail insists that the developer have a fuel supply contract in place that matches or comes close to the period covered by the financing.

  The IPP's views as to other terms of the contract (e.g., pricing) will depend heavily on terms of the power supply contract, i.e., the contract covering the sale of the power to an electric utility. The price paid for the electricity may, under some contracts, be tied to a utility's avoided cost or, more recently, indexed to some measure of the utility's fuel cost.

- *Traditional electric utilities* may or may not be interested in a long-term contract. The views will depend upon experience, future market expectations, and tolerance for risk. Electric utilities are responsible to their customers for procuring fuel at the lowest possible cost and their actions are subject to regulatory review on a post-audit basis, often long after the fuel has been used. Fuel costs that are found to be imprudent have to be refunded to customers—with the costs borne by shareholders.

  Views about desirable contract length differ among traditional electric utilities. For example:

  - An electric utility that once held a long-term coal contract with automatic price escalation, or prices indexed to miners' wage levels, or perhaps certain other mining costs probably found that the resulting price rose far above market prices. This utility may be leery of any long-term contracts with automatic price escalation.
  - An electric utility that believes energy supplies are likely to be plentiful in the future—with substantial interfuel competition—may conclude that long-term contracts are not a good way of keeping fuel prices in line with current markets unless the price is periodically adjusted to market. Such a utility may prefer all short-term contracts or a portfolio of

short-, medium-, and long-term contracts and spot purchases.

- An electric utility concerned about future supplies may conclude that it is reducing risk by committing to a long-term contract.
- In some cases, external factors may dictate the need for a long-term contract. For example, utilities depending upon Canadian gas supplies for all or a part of their needs found that:
  - They had to have long-term contracts (15-20 years) to satisfy the requirements of the Canadian National Energy Board (NEB) when the Board was considering capacity expansion on the TransCanada PipeLine System. The NEB did not approve capacity expansion unless reserves were identified for the duration of the firm transportation contract.
  - Provincial governments in Canada sometimes require that contracts be backed up with specifically identified proved reserves.
  - Canadian producers were willing to commit reserves for long-term contracts—in part because the reserves tended to be long-lived reserves.
- An electric utility may place high value on long-term relationships with particular suppliers that provide fuel meeting particular needs of the utility's generating units or provide flexibility in quantity of fuel that must be taken.
- An electric utility may or may not place high value on transaction costs. That is:
  - A utility may prefer a long-term contract to avoid the need to repeat the bidding, proposal, contractor selection, contract negotiation process
  - A utility may conclude that its cost of paying the people needed to play short-term and spot markets is more than offset by the savings achieved in obtaining fuel at costs below those paid under mid- or long-term contracts.

• *State regulators and the Federal Energy Regulatory Commission* generally have a strong interest in ensuring that regulated utilities procure fuel at the lowest delivered cost. Many of them have seen long-term contracts, particularly those with fixed escalators, result in prices that rose well above market levels. This has led some regulators to prefer spot purchasing, short-term contracts, and contracts that are indexed to competing fuel prices.

Long-term contracts are becoming much more flexible. Many modern "long-term" contracts may have 15 or 20 year terms but have pricing and renegotiation terms that make them more flexible than older long-term fuel supply contracts. Typical contract provisions might include:

- Prices indexed to the purchasing organization's cost for other fuels.
- Right for either party to call for renegotiation if prices under the contract deviate by some agreed-upon amount from prevailing markets, and, if renegotiation does not result in agreement, the contract may be terminated or submitted to binding arbitration.

Such contract terms have the advantage of maintaining long-term relationships while recognizing that future market prices are impossible to predict.

Indexed contract prices: Both the starting price and the index are important. Those who have experience with indexed prices in fuel contracts recognize that both the starting point and the index are important. A contract with an indexed price may provide little protection to either the buyer or seller if:

- The index is used merely as a measure of change rather than a way to tie contract prices to market prices and
- The starting price is not tied to a current market price.

Other important contract terms. A variety of other contract terms are also important to the electric generation industry. These include:

- Ability to vary the amount of gas taken during a particular period. This is important because generating units, other than base load, have highly variable periods of operation. Also, base load plants may not operate because of either scheduled or unscheduled maintenance and downtime. Such variations are particularly troublesome if storage is not available near the users' facilities and/or "balancing services" are not available to the user at costs that keep the use of gas competitive with other energy sources.

- Flexibility in terms of where gas may be delivered to a pipeline—in order to tie to gas transportation contracts.
- Right to sell gas to a third party if the gas is not needed and the purchaser is committed to demand charges.
- Avoiding "reservation" fees.

Impact of FERC Order 636. Some in the gas producing and transporting industry appear to have a strong preference for long-term gas contracts. Order 636, however, if it is implemented in a way that achieves the FERC's stated policy objectives, should result in a more competitive gas transportation market. Electric generators may be less interested in long-term contract commitments if they are convinced that there will be a competitive gas transportation market.

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. 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 from another state
- Sale of power from federally constructed hydroelectric facilities at less than full cost
- Federal and/or state subsidies for electricity via tax exemptions, loan guarantees, loans at below market interest rates, financing via the federal financing bank, and/or favorable repayment terms—which are available to Federal Power Marketing Agencies, rural electric cooperatives, and/or public power groups
- Subsidies provided by at least one Federal Power Marketing Agency to persons who construct energy efficient, electrically heated homes—which gives this organization's electricity sales a competitive advantage over gas and has the potential for increasing peak electricity demand
- Federal research and development funding for coal and nuclear energy projects
- Federal subsidies for cleaning up uranium wastes (mill tailings) and other nuclear energy wastes associated with commercial nuclear power projects.

Renewable Set-Asides

At least two states, California and Wisconsin, have adopted requirements that electric utilities obtain some portion of their incremental energy requirements from renewable energy sources. Such requirements tend to reduce potential demand for natural gas, which would otherwise have a good chance of competing because of the advantages cited earlier.

RECOMMENDATIONS FOR DEALING WITH CHALLENGES THAT MUST BE FACED AS THE ROLE OF GAS IN ELECTRIC GENERATION INCREASES

Previous sections of this chapter identify opportunities for increased use of natural gas in electric generation, indicate that aggressive action will be needed by organizations in the gas industry to capture market opportunities, and describe challenges that must be overcome in order to take advantage of the opportunities.

The NPC has identified many challenges to increased use of gas in electric generation, but it has concluded that actions already underway and others being recommended will be successful in assuring that gas will play a steadily growing role in supplying energy to generate electricity. In summary, the important challenges identified include:

- Competition from other energy sources

- Strong need to understand factors affecting electric generators' fuel needs and fuel choices—which vary widely among sites, applications, technologies, companies, distances from pipelines, regions, and constraints resulting from current and future environmental protection requirements
- Need to understand the differences between independent power producers and traditional electric utilities
- Strong need to understand and respond to electric generators' concerns, perceptions, and expectations, including the need to understand disadvantages of using gas—as perceived by potential customers—as well as the advantages are already understood
- 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
- Need to satisfy potential customers that supplies will be available when needed and that the delivered prices of gas will not become excessive compared to other energy sources after a capital investment has been made in a gas-fired generating facility.[24]

This section lists and describes the recommendations for dealing with these challenges. Many of the recommendations are self-evident and many flow from the findings of the focus groups and the task groups that organizations in the gas industry must become more customer oriented. This includes the need to:

- Learn more about electric generators' needs, perceptions, and expectations
- Improve customer service—to include an attitude that "if you may be interested in using gas, we'll help you find ways of using gas at lowest reasonable cost."

[24] Concern about future delivered prices becoming excessive compared to other energy sources should not be a problem if the generator has a secure long-term contract that provides gas at a delivered price at the generator's facility that remains competitive with other energy sources for the life of the contract.

The recommendations listed below are in five categories:

- Those most appropriate for individual organizations in the gas industry—producers, marketers, pipelines, LDCs, etc.—recognizing that these organizations will be in competition for available markets
- Those appropriate for industry-wide action, including some in support of individual company actions
- Those that require interaction and cooperation with the electric generation industry (in many cases, these may be the most difficult because of competition between gas and electricity, between individual electric companies and LDCs at the local level)
- Those that require action or participation by government agencies, particularly including regulators (rate, environmental, siting) at the state government level
- Those requiring action by the electric generation industry.

Recommendations for Actions by Companies in the Gas Industry

In the increasingly competitive environment of the gas industry, many of the actions needed are appropriate on an individual company basis. A discussion of such actions is shown below.

Deepening Employee Understanding of the Electric Generation Industry

Individuals engaged in planning, marketing, and transporting for companies in the gas industry need an understanding of electric generating companies at least as comprehensive as their competitors. Thus, companies in the gas industry should develop ways of exposing their planning and marketing staffs to:

- Factors affecting fuel choice decisions in the electric generation industry, with particular attention to site-specific factors and wide variation among potential applications, companies, technologies, and regions
- Developments affecting the electric generation industry, with particular attention

to Integrated Resource Planning (IRP) and the demand-side measures resulting from IRP that may be less costly for electric customers than supply-side measures

- Planning and decision-making processes in the electric generation industry
- The workings of power pools and principles of economic dispatch
- Electric generators' concerns and perceptions about the use of natural gas in electric generation, including all those described in this chapter
- Successful marketing approaches used by competitors when dealing with electric generators, including independent power producers and traditional electric utilities.

Improving Responsiveness to Customers

The matter of responsiveness to customer needs, perceptions, and expectations has been revealed by Focus Group and Task Group activities as a major obstacle to increased gas use. This matter must, in the final analysis, be addressed primarily at the individual company level.

Improving Competitiveness of Gas With Other Energy Sources

As indicated earlier, it is expected that conservation will reduce the rate of growth in demand for electricity and that gas, despite its advantages, will face rigorous competition from other energy sources for electric generating markets. Individual companies will need to take a variety of actions to keep gas more attractive than alternatives, including:

- Finding new ways to keep gas price competitive on a delivered cost basis (i.e., including both wellhead price and transportation cost), through action at all stages from exploration, through production, processing, transportation, and contracting to point of use.
- Identifying terms and conditions of sales and transportation arrangements that have value to particular customers in the electric generation industry (e.g., pricing, length of contract, variability of takes, flexibility of receipt and delivery points, integrated storage, and ability to reassign firm transportation capacity and resell gas supplies when generating units are not running), and develop proposals to meet such needs.

Addressing Electric Generators' Concerns, Perceptions, and Needs

Price expectations. As indicated earlier, price expectations play an important role in investment decisions involving choices among energy sources. A decision maker's price expectations are likely to be formed on the basis of formal and informal information from a variety of government and private sources, including statements by energy industry representatives about future supplies and prices. Executives in the gas industry should recognize that their public statements about future supply, demand, and price conditions—regardless of the intended audience—may play a part in decisions made by potential gas users.

Gas industry officials should:

- Present balanced and realistic assessments of the future outlook for natural gas supply and prices. Recognize that alarmist statements about the state of the domestic producing industry and its ability to meet increased gas at competitive prices demand undermine potential customers' confidence in using gas.
- Be prepared to demonstrate that gas prices are and will likely be, in the long run, competitive with other energy sources and conservation, after taking into account differences in capital and operating costs.

Delivered price of fuel. Producers and transporters need to recognize that it is the *delivered* price of gas—including both wellhead and transportation—that affects investment decisions and customers' bills and is the focus of electric utilities and their regulators when evaluating prudence of fuel procurement.

Adequacy of future gas supplies. Potential gas users in the electric generation industry are concerned about the adequacy of future gas supplies and the stability of gas prices.

The gas industry needs to recognize that continuation of these concerns are in the interest of competitors. The industry needs to work to convince electric generators and regulators that future gas supplies will be adequate. Actions should include:

- Actively publicizing information about:
  - New estimates of North American gas resource base, including information developed as a part of the NPC natural gas study
  - Improved ability to find and produce gas at lower cost than in the past (including new technology)
  - Recent finding and replacement cost experience
  - Changed requirements with respect to reserve-to-production ratios.
- Encouraging the Departments of Energy and the Interior to publicize recent information about resources, reserves, and replacement costs.

  Industry officials need to be prepared to identify assumptions made in developing resource base, reserve and production cost estimates, and to respond to tough questions about the validity and reliability of those estimates and about supply/price trade-off estimates.

  In addition, gas industry officials may want to encourage others to discontinue unwarranted actions that work to undermine confidence in future supplies and competitiveness of future prices, e.g., projections of supply shortages, and prorationing proposals that are not essential to protect correlative rights and for resource conservation.

Potential for short-term supply interruptions. As indicated earlier, some electric generators remain concerned about the potential for short-term interruptions of firm transportation and gas supplies in sustained periods of cold weather or unplanned pipeline and compressor outages, or well freeze-ups.

In various regions, pipeline companies serving the region should, in cooperation with appropriate producers, LDCs, and large end users of gas:

- Inform electric generators of the actions that have been taken since December of 1989 to enhance storage and guard against well freeze-ups.
- Undertake contingency planning, including analysis of potential pipeline and supply disruptions under various emergency conditions.
- Work with others in the region to establish continuing organizational arrangements to promote reliability planning and coordination.

Ability to provide volumes, pressures and variability. As indicated in earlier, electric generators in some regions are concerned about the ability of pipelines and LDCs to provide gas in the volumes, pressures and variability required for gas turbine peaking units and combined-cycle units. This matter must be addressed on a cooperative basis among elements of the gas and electric generating industries. However, individual companies should:

- Review the report on gas and electric utility integration recently issued by EPRI (and the draft report prepared by the electric and gas companies in New York) and
- Join in establishing regional groups that could:
  - Assemble information on an area or regional basis on existing and planned use of gas for electric generation and on capability of existing and planned pipeline capacity to serve incremental electric generation markets and
  - Assist in determining whether problems described in the EPRI report now exist or are likely to exist as gas use is increased, particularly in areas without significant experience in gas use in electric generation.

Importance of gas transportation costs. As indicated earlier, some potential electric generator users of natural gas are concerned about gas transportation costs—which costs may be the deciding factor in fuel choice decisions. Concerns are due to the impact of transportation costs in some regions and the potential for increases after capital investment commitments are made—particularly in noncompetitive markets.[25] Pipeline companies

[25] Competitive transportation markets are helping to hold down transportation costs through cost control measures for firm transportation and discounts for interruptible transportation.

and LDCs will need to develop ways to hold down transportation costs and provide assurances that costs will be competitive after capital investments are made in generating facilities.

Restructuring proceedings. Transportation costs are particularly important because of the issues and uncertainties associated with FERC Order 636 restructuring proceedings. These include various cost allocation issues (including transition costs), allocation of storage, penalties for variation in gas volumes, limitations on receipt and delivery points, ability to reassign firm transportation capacity and resell gas supplies when generating units are not running, and uncertainties as to how state regulatory commissions will handle their expanding responsibilities.

Pipeline companies and LDCs need to be aware of the importance of the above issues as they prepare and defend restructuring proposals.

Complexity of buying and transporting gas. Companies in the gas industry need to recognize that gas has a competitive disadvantage because of the difficulty of buying, transporting, and storing it. More services will be needed to reduce that customer burden or ways found to shift it to entities in the gas industry.

Recommendations for Industry-Wide Action

As indicated above, many of the findings by the NPC during this study focused on the needs for a better understanding of, and responsiveness to, existing and potential customers by organizations in the gas industry. Some of the actions can be taken on an industry-wide basis. A discussion of potential actions is included below.

Gas and Electric Industry Cooperation

Leaders in the gas industry look upon the recent EPRI report on gas and electric industry integration as an opportunity to expand their dialogue with the electric generation industry on the full range of electric generators' concerns about increased reliance on natural gas. Dialogue should include coverage of the issues covered by the EPRI report and open the way for detailed discussion of integration at the level of actual transactions.

Regional Reliability Groups

The gas industry should consider promoting or encouraging the establishment of regional groups to address reliability issues identified in this study as well as those identified by the Energy Council, the FERC/DOE Deliverability Task Force, and others.

Training Programs for Gas Industry Planners and Marketers

Gas industry associations should consider establishing training programs to help provide company planners and marketers with basic information and understanding of the electric generation industry; i.e.:

- Factors affecting fuel choice decisions in the electric generation industry, with particular attention to site-specific factors
- Developments affecting the electric generation industry, with particular attention to Integrated Resource Planning
- Planning and decision-making processes in the electric generation industry
- The workings of power pools and principles of economic dispatch
- Electric generators' concerns and perceptions about the use of natural gas in electric generation
- Successful marketing approaches used by competitors when dealing with electric generators.

Evaluation of Forecasts and Projections

Planners and marketers in the gas industry are faced with a variety of forecasts and projections of potential demand for gas in the electric generation industry. The forecasts are often based on widely differing assumptions and degrees of understanding of the electric generation industry. The Gas Research Institute (GRI) has already done considerable work for the gas industry to provide reliable forecasts but more could be done to assess specific projections (such as those compiled by the North American Electric Reliability Council, DOE, and Utility Data Institute), and to identify aspects that should be understood better by gas industry planners and marketers who are attempting to use them in their activities.

Inter-Industry Cooperation and Coordination—Gas and Electric Generation Industries

The NPC believes that there is much to gain by closer cooperation between the gas and electric industries as well as among the participants in the gas industry. Those gains include increased competitiveness for gas with other energy sources and lower costs for both gas and electric customers. To achieve the needed cooperation, executives in both industries will need to look for and promote opportunities where gas use can be beneficial to companies in both industries and their customers.

Promotion of Communication Among Officials of the Gas and Electric Generation Industries

Work on the NPC Natural Gas Study has revealed that there is a need for people in the gas and electric generation industries to improve communication and understanding of each others' concerns and points of view. Work is underway in each industry to deal with this obstacle,[26] but more could be done. Leaders in both industries should work to arrange opportunities for additional communication *at all appropriate levels*, including senior and mid-level executives and their staffs with responsibilities:

- For planning and power supply in electric generating companies and in power pools, and for generation planning and fuel procurement in electric utilities and
- In the gas industry for planning and marketing in producer, marketer, pipeline, and LDC organizations and for pipeline operations in pipeline companies.

This NPC report and the recent report by EPRI on the challenges of integrating the gas and electric industries provide a wealth of information that could be used to focus inter-industry communications.

[26] For example, efforts listed in Footnote 34.

Concerns About Adequacy of Volumes, Pressures, and Variability in Delivering Gas for Electric Generation

These concerns also need to be addressed on a cooperative basis among organizations in the gas and electric generation industries. In areas without substantial experience with gas use in electric generation that are prospects for increased use, pipelines, LDCs, electric generators and other large volume end users, and representatives of power pools should:

- Review the report on gas and electric utility integration recently issued by EPRI (and the draft report prepared by the electric and gas companies in New York), and join in establishing regional groups that could:
  - Assemble information on an area or regional basis on existing and planned use of gas for electric generation and
  - Prepare a checklist and assist in determining whether problems areas described in that report now exist or are likely to exist as gas use is increased, particularly in areas without significant experience in gas use in electric generation.
- Where there are potential problems, leaders of the gas *and* electric utility industries should encourage creation of coordinating groups (including Power Pool planners) to find solutions.

Recommendations Requiring Action or Participation by Government Agencies

While many of the challenges that must be addressed can be handled most effectively by organizations in the private sector, some will require action or participation by federal, state, or local government agencies. Actions needed include the following.

Optimizing the Use of Natural Gas and Back-up Fuels

When electric generating units have the capability to use an alternative or back-up fuel, it should be possible to work out arrangements, if pipeline capacity utilization rates are normally high, for sharing pipeline capacity and gas supplies between electric generators and LDCs that would minimize costs for both electric and gas customers and reduce adverse environmental impacts.

The NPC recommends that organizations in the gas industry and/or public utility commissions take the lead in working out sharing arrangements that would increase and help levelize pipeline throughput. For example, an electric generator might be assured access to pipeline capacity and gas supplies on days when demand for gas is low, and the LDC would have access on cold days when gas demand is high and the electric generator would burn its alternative or back-up fuel (often oil). This increased use of natural gas could result in additional cost savings for both gas and electric customers. In addition to realizing savings from maximizing pipeline throughput, emissions in electric utilities could be minimized by increasing the use of gas.

Working out such arrangements would require the support of LDCs, pipelines, electric generators, power pools, public utility commissions, environmental regulators, and environmental, energy conservation, and consumer advocate organizations.

Limitations on Use of Back-Up Fuels

Optimized arrangements such as those outlined above are effectively prevented when electric generators are restricted in the use of back-up fuels, e.g., to a certain number of days per year or only when gas is unavailable. Public utility commissions, environmental regulators, and siting boards should review restrictions on back-up fuels to determine whether they are truly cost effective—considering customer costs, reliability, and environmental impact.

Transportation Costs

FERC and state regulatory commissions should recognize concerns of potential gas users about transportation costs—both the absolute amounts and the potential for increases after investment decisions are made—and the impact of transportation cost on electric generators' fuel choice decisions, particularly as such costs and risks are affected by:

- FERC Order 636 restructuring proceedings
- Rolled-in vs. incremental rates
- Costs of capacity expansions exceeding pipelines' estimates
- Straight fixed variable rate design, which tends to increase the front-end commitment that an electric generator must make for firm transportation capacity
- Changes in regulations or rate design or other actions that have the effect of abrogating contracts between gas users and transporters or otherwise increasing transportation costs
- State implementation of FERC Order 636
- Concerns that electric generators, as large volume users, will be called upon to cross-subsidize core customers.

Subsidies for Competing Fuels

The Department of Energy should evaluate subsidies being provided to competitors of natural gas and determine whether such subsidies should be eliminated.

Data on Planned Changes in Electric Generating Capacity

The Energy Information Administration should consider increasing the data it collects and publishes on planned changes in electric generating capacity[27] to include (in addition to planned new units) addition of capability to use an additional fuel, repowering, life extension, and availability improvements. Planned actions such as these may prove to be as important as planned new generation. Data should include a description of the capability and fuel use for units before changes and the expected capability and fuel use after changes are made.

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[27] In the annual inventory of power plants.

Improving Electric Generation Industry Understanding of the Potential for Using Gas

As most gas use in electric generation has occurred in six states, many of the opportunities for increased use will be with electric generators that have not previously had experience with gas use. EPRI and the EEI have undertaken and are continuing some activities to increase understanding of the potential for natural gas, but additional actions to familiarize individuals in the industry with natural gas should be undertaken.

REGIONAL ANALYSES OF POTENTIAL NATURAL GAS USE FOR ELECTRIC GENERATION

The Demand and Distribution Task Group organized regional teams to analyze the potential for and obstacles to increased use of natural gas in each of the ten federal regions of the United States, and to prepare reports on their findings. The full reports of the regional teams have been published separately from the overall report.

Each region team provided information on current and potential gas use for electric generation. The leader of each team has provided the following summaries of findings with respect to electric generation.

Region One: Massachusetts, Connecticut, Rhode Island, Maine, New Hampshire, and Vermont

According to the Energy Information Administration's "State Energy Data Report Consumption estimates 1960-1990," Region One, with 5.2 percent of the U.S. population, produced only 3.8 percent of the nation's electricity in 1990. Natural gas accounted for only 6.6 percent of New England's energy input at electric utilities, while oil and coal accounted for 27.5 percent and 15.8 percent, respectively.

Overall natural gas consumption in Region One has been growing at a rate of approximately 3.5 percent per year over the past decade, with the majority of this growth in the electric generation sector. Consumption by electric utilities increased at an average annual rate of 25.8 percent from 1980-1990.

Although natural gas sales in New England have been growing over the past decade in contrast to declining sales in the overall U.S. over this period, New England still lags far behind the rest of the United States in terms of market penetration for natural gas. Natural gas provided 14.7 percent of total primary energy in New England in 1990 compared to 24.1 percent for the U.S. (excluding New England).

Both the traditional markets and the power generation market for natural gas are projected to continue to grow in New England during the next decade at a pace greater than the nation as a whole because of several factors including: the low starting point for the region's gas market, the region's more stringent environmental legislation and regulation that favors natural gas, and competitive prices. Gas consumption in the electric generation sector has been forecast to reach between 180 and 310 trillion BTU (TBTU) in the year 2000, as compared with 1990 consumption of 69.5 TBTU. Therefore, there is significant potential for growth in this market over the next decade.

The growth in natural gas consumption that has taken place in New England to date has largely resulted from the availability of increased gas supply and pipeline capacity additions that have occurred over the past 10 years. The region's LDCs were successful in developing "self-help" type natural gas supplies during the 1980s with Boundary Gas, Alberta Northeast Gas, and the conversion of the Portland Pipeline to natural gas.

Region Two: New York and New Jersey

In the electric utility generation sector, natural gas gained relatively little market share in Region Two over the two decades of the 1970s and 1980s. Gas consumption for electric generation declined markedly in the mid-1970s and then regained its original market share during the 1980s. Petroleum lost significant market share, however, with a decline from 41 percent to 26 percent, and nuclear power gained 20 percent of the share of electric generation fuel consumption.

The rest of the United States showed substantial declines in the relative consumption of natural gas within the electric generation sector. The national market share of natural gas in this sector dropped from 26.4 percent in 1970 to 9.6 percent in 1989. Region Two has a high dependence upon oil for generation, 26 percent of market share in 1989 compared with 4 percent in rest of the United States. The rest of the United States is more heavily dependent upon coal for electric generation. In 1989, coal comprised 57 percent of the U.S. fuel consumption for electric generation: in Region Two coal accounted for only 19 percent of fuel consumption in the electric generation market. Even though Region Two still relied on oil to supply 26 percent of its fuel for electric generation in 1989, it has significantly reduced this dependence in the past two decades and has increased the use of natural gas in this sector. In the rest of the United States, however, the market share of coal for the electric generation increased from 46 percent to 57 percent from 1970 to 1989 while relative natural gas consumption declined.

Due to competitive forces and growing environmental concerns, natural gas has become an increasingly attractive fuel source option in recent years. Many electric utilities in Region Two have converted some of their oil-fired generating units to natural gas or dual fuel capability, are building new gas-fired generating facilities, or are considering doing so. In addition, the majority of new non-utility generating units (NUGs) in the region are gas-fired. The most common problems and worries of these electric utilities and NUGs are related to natural gas availability, price fly-up, operational mismatches between electric plants and the current gas infrastructure, and regulatory uncertainty.

New York and New Jersey Gas Utilities forecast the consumption of natural gas for electric power generation to more than double from the 1990 level of 288 TBTU to 735 TBTU by 1995 as natural gas fired NUGs come on-line. The electric generation level is projected decrease to 683 TBTU by 2010 as older utility-owned units are retired and replaced by more efficient gas units. The net effect of this process is uncertain. If all currently planned units come on-line as projected, by 1995 the reserve margins of the electric utilities in Region Two will be very high. To compensate for the reduced level of need and excess capacity in the mid-1990s, these electric utilities will build fewer new units than they retire in the following fifteen years. However, if electric demand side management (DSM) programs are not as effective as anticipated, natural gas consumption may continue to increase beyond 1995 levels.

Supply shortages and curtailments in the 1970s damaged the confidence of consumers in natural gas as a long-term energy source. Because of price uncertainty, conversions to dual fired units by some New York utilities were made on a required pay-back period of less than three years. Lack of coordinated supply and demand planning by pipelines and local distribution companies (LDCs) is also of concern to the electric generation market.

Finally, the remaining major regional uncertainty is the regulatory climate over the next few years. The adoption of the Straight Fixed Variable (SFV) method of rate design in FERC Order 636 may have a negative effect on the growth of natural gas consumption by Region Two electric utilities. Since SFV allocates the majority of transportation costs to the fixed demand charge, LDCs in Region Two, and consequently their firm customers, are concerned that they will incur higher gas service costs, especially if the interruptible market demand is inadequate to provide the necessary cost offsets. Further, since the interruptible market is very sensitive to price, it may also be lost to alternate fuel competition. All of these factors are likely to encourage Region Two gas utilities and combination gas and electric companies to utilize market area storage options over long-haul firm transportation because the price margins between gas and residual fuel may be too uncertain for making twenty-year firm transportation commitments. Under Order 636, Region Two LDCs will have increased exposure to fixed payments, and may be forced to pass on such a rate structure to electric generators to insure recovery of their costs. The price risk perceived by electric utilities between oil and gas, and the fact that the alternate fuel for gas-fired NUGs is distillate oil, creates a natural bias in Region Two toward the NUG generation market and away from central station generation. This is especially true in Region Two where transportation costs are high relative to other parts of the country.

Despite impediments, state and local environmental policies and development goals provide significant incentives to electric utilities to expand the use of gas for generating electricity over the next two decades.

Region Three: Delaware, Pennsylvania, Maryland, Virginia, West Virginia, and Washington, D.C.

Natural gas is used to generate approximately 2.7 percent of the electric energy produced in Region Three.

Natural gas deliveries to the electric generation market in Region Three have increased dramatically during the past five years and this growth is expected to continue over the next ten years.

In Region Three, electric utilities need modest additions to their generating capacity to meet load growth and to offset generating capacity reductions from power plant retirements and deratings. Approximately 100 existing boilers at power plants throughout Region Three are candidates for gas co-firing or gas seasonal firing. Table 5-7 presents a state-by-state summary of the new power plants and conversions of existing power plants to natural gas that are forecasted for the ten-year period 1992-2001.

Region Four: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee

The region currently produces 22.5 percent of the nation's electricity. Natural gas accounts for about 10 percent of the region's power generation by electric utilities, virtually all in Florida and Mississippi.

After declining considerably in the early seventies, gas use stabilized and began to grow again in the mid eighties.

The 1990 EIA inventory of power plants identified gas fired power plant additions, excluding Florida, equal to 65 percent of the 1990 year ending base (though much of this is for peaking use and will have a relatively low impact on gas demand).

In Florida, in which power generation accounts for 60 percent of gas consumption, the limitation on power generation gas use has been pipeline capacity. Florida Gas Transmission added 100 million standard cubic feet per day (MMSCF/D) capacity in 1992 and another 530 MMSCF/D is slated for 1994. About 80 percent of the 1994 expansion is contracted for by power generators. A load factor of about 75 percent is anticipated. ANR, United, and Florida Power Corp. have all been working on proposals for a new pipeline in the

TABLE 5-7

REGION THREE
NEW NATURAL GAS FIRED POWER PLANTS
AND EXISTING POWER PLANT CONVERSIONS TO NATURAL GAS
DURING THE 1992-2001 PERIOD

State	New Gas Fired Power Plants (Megawatts)	Existing Power Plant Conversions to Natural Gas (Megawatts)
Delaware	160 mw	None Planned
Washington, D.C.	0 mw	50 mw*
Maryland	500 mw	500 mw
Pennsylvania	3,300 mw	1,500 mw
Virginia	2,400 mw	0 mw
West Virginia	No Information	No Information

* Planned Cogeneration Facility.

state potentially yielding another 300 to 800 MMSCF/D over the next decade—mostly for power generation.

Region Five: Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin

The region depends on coal to generate electricity. Demand for coal dwarfs that for either natural gas or oil and this dominance is expected to continue through the turn of the century. Coal is favored over other fuels due to its relatively low cost. However, by 2010, natural gas and oil will account for 12 percent of electric utilities' fossil fuel demands.

Environmental concerns will have an effect on the use of high sulfur coal in the region's coal-fired power plants. Currently a new technique of blending natural gas with coal is being tried, but the technique is still expensive.

Region Five is expected to add generating capacity after the year 2000. The first need will be peaking capacity. Combustion turbine plants will be built to fill the peak load void since the fixed costs are lower than combined cycle plants.

Intermediate load will also be needed around 2001 or 2002. Combined-cycle gas plants are expected to win due to their lower fixed costs compared to competitive fuels.

Region Five is not expected to need additional baseload capacity until after 2005.

Region Six: Arkansas, Louisiana, New Mexico, Oklahoma, and Texas

The states of Oklahoma and Texas account for 85 percent of overall gas consumption in the region.

In 1991, gas delivered to consumers in the region totaled 5.4 TCF. (This does not include lease, plant, and pipeline fuel). Of this amount, 1.6 TCF (29 percent) was by electric utilities. Texas electric utilities consumed over 1.0 TCF.

Coal is the principal fuel used for power generation, accounting for almost half the electricity generated in the region. Nuclear plants account for about 15 percent. In 1993, a new nuclear plant, Comanche Peak Unit 2, will come onstream. But, over the next decade, gas should compete favorably with coal and nuclear for capacity additions and repowering.

Overall, gas usage for utility power generation is expected to grow 1 percent annually through 2000.

Region Seven: Iowa, Kansas, Missouri, and Nebraska

The electric generation market for gas consists of electric utility-owned generating units and independent power producers. This market segment has the greatest potential for growth during the next two decades. Coal accounts for approximately 75 percent of the fuel used for power generation in the region. Obstacles to increased gas use include: (1) lack of adequate transportation capacity in some regions; (2) regulatory risk associated with the use of interstate pipelines; and (3) continuing concern over long-term supply availability.

Given current fuel price relationships and environmental factors, natural gas-fired capacity can be expected to dominate new investment. North American Electric Reliability Council (NERC) surveys of expected capacity additions in the West North Central census region reveal that the share of gas-fired capacity will increase from 8 percent in 1991 to *potentially* 15 percent by 2000. Further, because of the time required to build new coal-fired facilities, it is unlikely that significant additions could occur before the turn of the century, even if economics favored coal. As a result, gas would benefit from faster-than-expected load growth.

As a result of the rapid additions to gas-fired capacity, the region's average annual growth rate in gas consumption for power generation is expected to be 17 percent through 2000. This compares with the 0.7 percent growth rate projected for coal usage. By 2010, the share of gas usage in power generation is expected to rise to 13 percent, compared to 2 percent in 1991.

The 1990 amendments to the Clean Air Act require reductions in SO2 and NOx emissions from electric utility plants. With its relatively clean-burning properties, natural gas could increase its share of the utility market as a result of this legislation. The utilities are faced with numerous options in complying with the Clean Air Act requirements. These options include: switching from high sulfur to low sulfur coal, scrubbing of high sulfur coals, natural gas reburn and sorbent injection, natural gas co-firing, and combined-cycle repowering. For the region, given the proximity to low sulfur coal producing areas, switching from high sulfur coal to low sulfur coal is likely to be the compliance method of choice. While switching to gas may be a viable option based on economics, increased gas usage as a compliance option is not likely to be significant.

The strategic location of the region between Alberta and the Gulf Coast and its accessibility to the Rocky Mountain gas producing areas provide it with a variety of supply options. This analysis indicates that existing and proposed gas pipeline expansion projects are adequate to meet the region's expected gas demand for the next decade. By the year 2000, the region would require additional gas pipeline capacity to transport gas from Western Canada.

Region Eight: Montana, Wyoming, Utah, Colorado, North Dakota, and South Dakota

The electric utility generation market in Region Eight is dominated by coal. The abundance of clean, inexpensive coal throughout Region Eight has made coal the fuel of choice for utility generation. Of the 30,467 mw of generating capacity in Region Eight, over 22,000 mw utilize coal while hydro units accounted for 6,020 mw of generation. In contrast, gas accounted for only 870 mw or less than 3 percent of total generation capacity in Region Eight. In analyzing fuel consumption for electric generation in Region Eight, natural gas consumption accounted for 10 trillion BTUs in 1989 or 0.61 percent of the electric generation market. Coal accounted for 1,385 trillion BTU or 84.45 percent of the market in Region Eight.

Natural gas will continue to fight a difficult battle with coal for the electric utility generation market in this region. Yet, as a result of the Clean Air Act legislation and other environmental concerns, natural gas is becoming a stronger competitor to coal in the repowering of obsolete facilities. A number of electric utilities in the region are considering options that will economically increase the efficiencies and plant life of older or obsolete power generating facilities.

Region Nine: California, Arizona, and Nevada

Electric utilities in Region Nine use approximately 27 percent of all primary energy consumed in the region to generate electric power. Demand for electricity is driven primarily by the electric requirements of the weather sensitive residential and commercial markets which account for some 73 percent of the total electricity consumed in Region Nine.

Natural gas is the dominant fuel in the region's utility electric generation (UEG) sector, accounting for 43 percent of the electric generating capacity and satisfying almost 30 percent of the market's fuel requirements. Over 87 percent of the gas consumed at UEG facilities in 1989 was used in California to meet base, intermediate, and peaking electricity needs.

Coal accounts for about 22 percent of the region's primary UEG fuel needs with only 13 percent of the generating capacity. In Arizona and Nevada, gas is used only to satisfy peak demand. Coal provides over 65 percent of these two state's UEG energy consumption.

Nuclear energy captured about 22 percent of the region's UEG market share in 1989, equal to that of coal. With 1200 mw of new nuclear capacity added within the last three years, nuclear's market share should increase as those plants are brought up to rated capacity.

The large majority of Region Nine's electricity is generated by facilities owned and operated by local municipal and investor-owned electric utilities. However, cogeneration and other non-utility generation accounts for a substantial part of the electric generation market. California leads the nation in the amount of electricity supplied by non-utility generators. In 1990, non-utility generators represented over 10 percent of the state's total electric generation capacity.

Gas-fired electric power generation will likely be the fuel of choice for most electric power capacity additions in Region Nine. In California, gas use for power generation is projected to grow by almost 40 percent by 2010. In Nevada, the gas market share will increase only modestly as gas additions will be limited to peaking units and some new non-utility generation. In Arizona, gas's market share may decrease as current excess coal and nuclear generating capacity is utilized to meet electricity demand growth.

Region Ten: Washington, Oregon, and Idaho

Region Ten currently relies on hydroelectric plants to provide an inexpensive source of energy. Approximately 80 percent of the region's generating capacity is provided by hydro generation giving this area the lowest electricity prices in the country. The region accounts for over 40 percent of the nation's hydro generation.

With the large amount of hydropower available the demand for fossil fuels in the generation of electricity is small. In fact the region consumes the least fossil fuels in the country. Coal dominates the fossil fuel demand that does exist, with gas and oil bringing up the rear.

The region currently has enough electric generating capacity to serve its projected demand through the turn of the century. Additional capacity for peak generation is planned for 1996. Primary plants used for this are combustion turbine and combined-cycle. Both can be fired by either oil or gas.

By 2010, the region will need baseload capacity to supplement its hydro projects and is expected to build 760 megawatts of coal capacity to meet that need.

ATTACHMENT #1

NUCLEAR GENERATING UNITS IN THE UNITED STATES
LISTED CHRONOLOGICALLY BY YEAR OF OPERATING LICENSE EXPIRATION

Year License Expires	Plant & Unit	State	Summer Capacity (MW)	Operator	Jointly Owned Unit
1993	San Onofre 1	CA	436	Southern California Edison	X
1993	Trojan	OR	1,104	Portland General Electric Co.	X
2000	Big Rock Point	MI	67	Consumers Power Co.	
2006	Dresden 2	IL	772	Commonwealth Edison Co.	
2007	Haddam Neck	CT	560	Connecticut Yankee Atomic Power Co.	X
2008	Diablo Canyon 1	CA	1,073	Pacific Gas & Electric Co.	
2008	Fort Calhoun 1	NE	476	Omaha Public Power District	
2008	Maine Yankee	ME	870	Maine Yankee Atomic Power Co.	X
2009	Ginna	NY	470	Rochester Gas & Electric Co.	
2009	Oyster Creek	NJ	610	GPU Nuclear Corp.	X
2009	Nine Mile Point 1	NY	605	Niagara Mohawk Power Corp.	
2010	Millstone 1	CT	652	Northeast Nuclear Energy Co.	X
2010	H.R. Robinson 2	SC	683	Carolina Power & Light Co.	
2010	Monticello	MN	532	Northern State Power Co.	
2010	Diablo Canyon 2	CA	1,087	Pacific Gas & Electric Co.	
2010	Point Beach 1	WI	495	Wisconsin Electric Power Co.	
2011	Pallisades	MI	755	Consumers Power Co.	
2011	Dresden 3	IL	773	Commonwealth Edison Co.	
2012	Turkey Point 3	FL	666	Florida Power & Light Co.	
2012	Surry 1	VA	781	Virginia Electric & Power Co.	
2012	Pilgrim 1	MA	663	Boston Edison Co.	
2012	Quad Cities 1	IL	769	Commonwealth Edison Co.	X
2012	Quad Cities 2	IL	769	Commonwealth Edison Co.	X
2012	Vermont Yankee	VT	496	Vermont Yankee Nuclear Power Corp.	X
2013	Zion 2	IL	1,040	Commonwealth Edison Co.	
2013	Indian Point 2	NY	931	Consolidated Edison Co.	X
2013	Prairie Island 1	MN	507	Northern States Power Co.	
2013	Point Beach 2	WI	495	Wisconsin Electric Power Co.	
2013	Kewaunee 1	WI	519	Wisconsin Public Service Corp.	X
2013	Browns Ferry 1	AL	1,065	Tennessee Valley Authority	
2013	Zion 1	IL	1,040	Commonwealth Edison Co.	
2013	Turkey Point 4	FL	666	Florida Power & Light Co.	
2013	Oconee 1	SC	846	Duke Power Co.	
2013	Peach Bottom 2	PA	1,051	Philadelphia Electric Co.	X
2013	Surry 2	VA	781	Virginia Electric & Power Co.	
2013	Oconee 2	SC	846	Duke Power Co.	
2014	Oconee 3	SC	846	Duke Power Co.	
2014	Tnree Mile Island 1	PA	808	GPU Nuclear Corp.	X
2014	James A. FitzPatrick	NY	800	Power Authority of State of NY	
2014	Peach Bottom 3	PA	1,035	Philadelphia Electric Co.	X
2014	Arkansas Nuclear One 1	AR	836	Arkansas Power & Light Co.	
2014	Calvert Cliffs 1	MD	825	Baltimore Gas & Electric Co.	
2014	Browns Ferry 2	AL	1,065	Tennessee Valley Authority	
2014	Edwin I. Hatch 1	GA	744	Georgia Power Co.	X
2014	Brunswick 2	NC	754	Carolina Power & Light Co.	X
2014	Duane Arnold 1	IA	515	Iowa Electric Light & Power Co.	X
2014	Donald C. Cook 1	MI	1,000	Indiana Michigan Power Co.	
2014	Cooper Station	NE	778	Nebraska Public Power District	
2014	Prairie Island 2	MN	503	Northern States Power Co.	
2015	Indian Point 3	NY	980	Power Authority of State of NY	
2015	Millstone 2	CT	863	Northeast Nuclear Energy Co.	X
2016	Crystal River 3	FL	820	Florida Power Corp.	X
2016	Salem 1	NJ	1,106	Public Service Electric & Gas Co.	X
2016	Calvert Cliffs 2	MD	825	Baltimore Gas & Electric Co.	
2016	St. Lucie 1	FL	839	Florida Power & Light Co.	
2016	Beaver Valley 1	PA	810	Duquesne Light Co.	X
2016	Brunswick 1	NC	767	Carolina Power & Light Co.	X
2016	Browns Ferry 3	AL	1,065	Tennessee Valley Authority	

ATTACHMENT #1 (Continued)

Year License Expires	Plant & Unit	State	Summer Capacity (MW)	Operator	Jointly Owned Unit
2017	Donald C. Cook 2	MI	1,060	Indiana Michigan Power Co.	
2017	Davis-Besse 1	OH	873	Toledo Edison Co.	X
2017	Joseph M. Farley 1	AL	812	Alabama Power Co.	
2018	Edwin I. Hatch 2	GA	762	Georgia Power Co.	X
2018	Arkansas Nuclear One 2	AR	858	Arkansas Power & Light Co.	
2018	North Anna 1	VA	911	Virginia Electric & Power Co.	X
2020	Salem 2	NJ	1,106	Public Service Electric & Gas Co.	X
2020	Sequoyah 1	TN	1,122	Tennessee Valley Authority	
2020	North Anna 2	VA	909	Virginia Electric & Power Co.	X
2021	McGuire 1	NC	1,129	Duke Power Co.	
2021	Joseph M. Farley 2	AL	824	Alabama Power Co.	
2021	Sequoyah 2	TN	1,122	Tennessee Valley Authority	
2022	LaSalle 1	IL	1,048	Commonwealth Edison Co.	
2022	Grand Gulf 1	MS	1,143	System Energy Resources Inc.	X
2022	Summer 1	SC	885	South Carolina Electric & Gas Co.	X
2022	San Onofre 2	CA	1,070	Southern California Edison	X
2022	San Onofre 3	CA	1,080	Southern California Edison	X
2022	Susquehanna 1	PA	1,040	Pennsylvania Power & Light Co.	X
2023	McGuire 2	NC	1,129	Duke Power Co.	
2023	St. Lucie 2	FL	839	Florida Power & Light Co.	X
2023	Washington Nuclear 2	WA	1,100	Washington Public Power Supply Sys.	
2023	LaSalle 2	IL	1,048	Commonwealth Edison Co.	
2024	Catawba 1	SC	1,129	Duke Power Co.	X
2024	Callaway 1	MO	1,125	Union Electric Co.	
2024	Waterford 3	LA	1,075	Louisiana Power & Light Co.	
2024	Byron 1	IL	1,120	Commonwealth Edison Co.	
2024	Limerick 1	PA	1,055	Philadelphia Electric Co.	
2024	Susquehanna 2	PA	1,044	Pennsylvania Power & Light Co.	X
2024	Palo Verde 1	AZ	1,270	Arizona Public Service Co.	X
2025	Wolf Creek 1	KS	1,131	Wolf Creek Nuclear Operating Co.	X
2025	Millstone 3	CT	1,137	Northeast Nuclear Energy Co.	X
2025	Palo Verde 2	AZ	1,270	Arizona Public Service Co.	X
2025	Fermi 2	MI	1,060	Detroit Edison Co.	X
2025	River Bend 1	LA	936	Gulf States Utilities Co.	X
2026	Braidwood 1	IL	1,090	Commonwealth Edison Co.	
2026	Hope Creek 1	NJ	1,031	Public Service Electric & Gas Co	X
2026	Byron 2	IL	1,120	Commonwealth Edison Co.	
2026	Nine Mile Point 2	NY	1,080	Niagara Mohawk Power Corp.	X
2026	Clinton 1	IL	930	Illinois Power Co.	X
2026	Shearon Harris 1	NC	860	Carolina Power & Light Co.	X
2026	Perry 1	OH	1,169	Cleveland Electric Illuminating Co.	X
2026	Seabrook 1	NH	1,150	Public Service Co. of NH	X
2026	Catawba 2	SC	1,129	Duke Power Co.	X
2027	Braidwood 2	IL	1,090	Commonwealth Edison Co.	
2027	Beaver Valley 2	PA	833	Duquesne Light Co.	X
2027	Vogtle 1	GA	1,104	Georgia Power Co.	X
2027	South Texas Project 1	TX	1,250	Houston Lighting & Power Co.	X
2027	Palo Verde 3	AZ	1,270	Arizona Public Service Co.	X
2028	South Texas Project 2	TX	1,250	Houston Lighting & Power Co.	X
2029	Vogtle 2	GA	1,103	Georgia Power Co.	X
2029	Limerick 2	PA	1,055	Philadelphia Electric Co.	
2030	Commanche Peak 1	TX	1,150	Texas Utilities Electric Co.	
2033 (Est.)	Commanche Peak 2	TX	1,150	Texas Utilities Electric Co.	

SOURCES: Nuclear Regulatory Commission, 1992 Information Digest, pp. 48-49; U.S. Energy Information Administration, "Inventory of Power Plants in the United States 1991," DOE/EIA-0095(91), Table 20; Gas Research Institute; and Edison Electric Institute.

ATTACHMENT #2

LIST OF ASSUMPTIONS THAT AFFECT NPC MODEL OUTPUTS WITH RESPECT TO POTENTIAL GAS USE IN ELECTRIC GENERATION

The NPC model outputs are driven by the assumptions fed into the model and the interworkings of the model. Because the assumptions are so important to the outputs and because they are based on judgments of the future subject to considerable debate, the following list is provided so that the reader can be as informed as possible as to the assumptions that have been made. (The numbers below refer to pages in Chapter Eight.)

ATTACHMENT #3

IDENTIFYING FACTORS THAT AFFECT ELECTRIC UTILITY[28] FUEL CHOICE DECISIONS

Fuel choices made by electric generators—particularly choices between coal and natural gas—are expected to have a significant impact on the amount of natural gas used in electric generation in the years ahead.

During its study of the potential for gas demand, the Demand and Distribution Task Group has found that:

- The potential for natural gas in electric generation varies widely by site, potential application, region, and generating company, but this wide variation seems not to be taken into account by some who attempt analyses of fuel choices
- Companies in the gas industry that may wish to sell or transport natural gas for electric generation and others that do analyses of electric generators' alternatives appear not to have a sufficient understanding of the factors—particularly site specific factors—that affect electric generators' fuel choices[29]
- Assumptions included in analyses—particularly assumptions about future fuel costs (including fuel and transportation)—often have an overwhelming impact on the results of the analysis.

Further, some organizations that have misconceptions about factors important in fuel choices may have been dissuaded from marketing efforts because they have incorrectly assumed that electric generators choosing coal "have a coal bias" or "prefer generating units that have a high capital cost."

This attachment has been prepared to help provide an improved understanding of the factors that affect electric utility fuel choice decisions and, hopefully, to provide a basis for improving analyses of such decisions.

More specifically, the following shortcomings appear to exist in many analyses of fuel choice alternatives:

Fuel Price Assumptions

As indicated above, assumptions about future fuel prices often dictate the outcome of analyses. Figures 5-1 and 5-2 show assumptions as to delivered fuel prices used in integrated resource plans submitted to state regulatory agencies by five eastern utilities. Particularly striking are:

- The wide variations among utilities in their price expectations
- The perception by all these utilities that coal prices will grow little if any while a few expect sharp growth in natural gas prices
- The high natural gas price expectations of some of these utilities seems to ignore the strong possibility that interfuel competition will keep natural gas prices competitive with other fuels.

These price assumptions suggest that decision makers in electric utilities (and their regulators) need to pay close attention to the assumptions used in their fuel choice analyses and be aware of the impact of those assumptions on the conclusions.

Insufficient Attention to Factors Affecting Fuel Choices That Vary by Site, Region, Company, etc.

Table 5-8 (at the end of this Attachment) is a matrix identifying many of the factors, including site specific factors, that will often have to be taken into account when analyzing electric generators' fuel choices. This matrix is offered as one step toward improved understanding of fuel choice decisions in electric generation markets.

Advantages of Adding Another Generating Unit at an Existing Site Compared to Building a Unit at a New Site

Those who wish to market gas to electric utilities need to be aware, in particular, of the

[28] Factors affecting non-utility generators' decisions are often different from those of traditional electric utilities.

[29] As indicated earlier, major changes in energy markets and regulation in the natural gas industry have resulted in new roles and responsibilities and the need for organizations in the gas industry to develop new knowledge of potential customers.

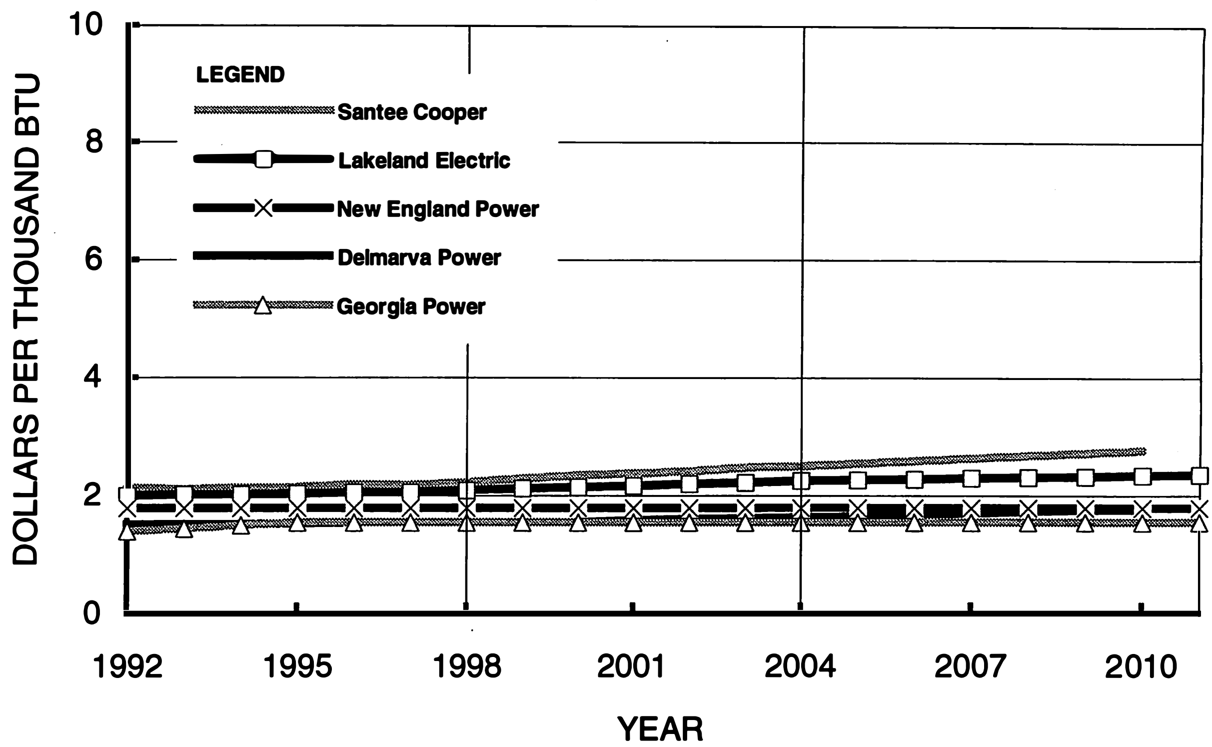
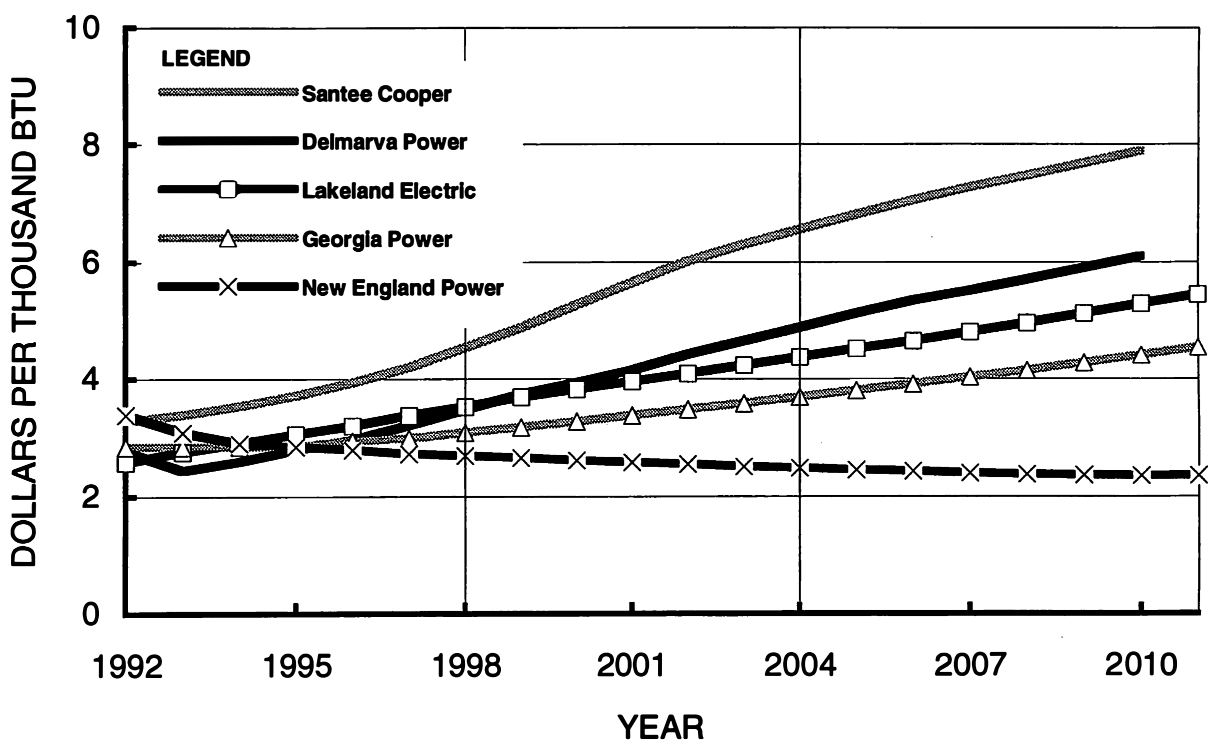


Figure 5-1. Coal Price Projections (Constant Dollars).



SOURCE: Integrated Resource Plans.

Figure 5-2. Natural Gas Price Projections (Constant Dollars).

impact on economics of the potential for building another generating unit at an existing generating station rather than at a new site. (This may be particularly important, for example, in understanding the economics of adding a new coal-fired unit at an existing station that has one or more coal-fired units, compared to building a gas-fired unit at a new site.)

Adding a new generating unit at an existing site can result in substantially less cost than at a new site for such reasons as the following:

1. Ability to make use of common facilities, e.g., substations, transmission lines, fuel storage areas and handling equipment, maintenance and service facilities and staff, control room, and administrative support.
2. Ability to use fuel transportation infrastructure already in place, e.g.:
   - Rail line—less cost in running more trains over existing rails than in building new rail connection.
   - Increase throughput on an existing pipeline that is not used at full capacity or where throughput can be increased with compression or looping.
3. Less neighbor and public opposition to adding a new unit at an existing plant site.
4. Possibly less permit approval time for an existing plant site than a new plant site.
5. Construction time may be less at an existing site.
6. May be able to add generating capacity in smaller increments at an existing site.
7. Sources of water supply may be in place.
8. Waste disposal facilities (on-site and off-site) may be in place.
9. Business relationship may be in place for services for the site.

Other Economic Factors That May Be Overlooked

1. Potential advantages of repowering, extending the useful life or increasing the availability of an existing generating unit. Electric utilities needing additional capacity often find that one of these actions at an existing site will be far less costly than a new "greenfield" facility.
2. Fuel transportation costs—which are important in the case of gas and coal; e.g.:
   - In the case of coal, the transportation alternatives available for the site (rail, water, truck, pipeline, or conveyor) and ability to get competition among transporters.
   - In the case of natural gas, the distance to the nearest gas pipeline that can provide the needed volumes, pressures and variability in "takes," whether there is competition among transporters, and, if not, the rate designs that can have a major impact on electric utilities' gas transportation costs.
3. Costs that vary significantly by region (e.g., labor costs).
4. Costs that vary by company, such as cost of capital due to different capital structures (debt/equity).
5. Needs that a particular utility may have to take into account to achieve such objectives as:
   - Bringing its estimates of future demand and future generating capability into balance
   - Meeting specific environmental requirements
   - Improving service reliability
   - Maintaining or increasing operating flexibility in the event of fuel market changes
   - Minimizing customer costs.
6. Alternatives other than adding generation capacity to bring supply and demand into balance, such as:
   - Undertaking or expanding conservation or load management activities to reduce the need capacity or generation ("demand-side")
   - Buying power from other sources (another utility with excess generating capacity, cogenerator, independent power producer, etc.).

"Non-Economic" or Non-Quantifiable Factors That Can Overwhelm "Economic" Factors

1. Public or neighbor opposition to a particular energy source (e.g., coal, nuclear, or gas).
2. An electric utility's current fuel mix (coal, oil, gas, nuclear, hydro, renewables) and possible desire to diversify its energy sources and gain some protection against future changes in market conditions.
3. Diversity of fuel supply sources and of transportation sources to permit taking advantage of competition among fuel suppliers and/or transporters.
4. Perception as to relative security of fuel supply; e.g., greater comfort that coal will be available continually at a low price, or that gas supplies may be interrupted.
5. Uncertainty and degree of control over future transportation costs (e.g., in the case of natural gas, can pipeline transportation rates be increased by the pipeline or its regulators?)
6. Conditions imposed by state or local siting boards, environmental authorities or regulatory commissions (e.g., limits on the use of back-up fuels, even when they would be cheaper for electric customers).
7. Confidence in the technology (e.g., a utility may have more confidence in a gas turbine that has been used successfully elsewhere than it has in a fluidized bed coal-fired unit that is being scaled-up for the first time).
8. Relative complexity (or ease) of procurement and delivery of various fuels to generating plants.

TABLE 5-8
FACTORS, INCLUDING SITE-SPECIFIC, LIKELY TO AFFECT COSTS ASSOCIATED WITH CHOICES BETWEEN COAL AND GAS FOR NEW GENERATING CAPACITY*

Factor affecting cost:	Costs differ for new vs. existing site?	Factor important in coal vs. gas decision?	Costs vary by region?	Costs vary by electric utility?
A. Capital Costs				
1. Key Variables:				
a. Fuel	Probably	Yes	Yes	Probably not
b. Plant type & technology	Yes	Yes	Yes	Probably not
c. Type load to be served (base, cycling, peak)	No	Yes	No	Probably not
2. Key elements of cost:				
a. Land cost	Yes	Yes	Yes	Probably not
1) Plant site				
2) Waste disposal site (if needed)				
3) Rights-of-way				
b Plant & equipment cost	Yes	Yes	Yes	No
c. On-site construction costs	Yes	Yes	Yes	Probably not
d. Cost of capital	No	No	Yes	Yes
e. Electrical transmission connection	Yes	No	Yes	No
f. Fuel receiving & storage (e.g., dock, tanks, pipeline connection, storage area)	Yes	Yes	No	No
g Water supply & pipeline	Probably	Yes	Yes	Probably not
h. Taxes	Possibly	Yes	Yes	No
B. Preconstruction costs:				
1. Key variables				
a. Federal, state, and local requirements	Yes	Yes	Yes	No
b. Time required to get through the permit process	Yes	Yes	Yes	No
c. Acceptability of plant or unit to neighbors, political leaders & regulators	Yes	Yes	Yes	No
2. Key elements of cost				
a. Environmental studies	Yes	Yes	Yes	No
b. Permits: applications, hearings	Yes	Yes	Yes	No
c. Public relations	Yes	Yes	Yes	Yes

* New generating capacity, as used here, includes entirely new units at existing or new sites and other changes, sometimes referred to as "repowering" which may include a variety of actions ranging from the addition of one or more gas or oil-fired turbines and capturing waste heat to produce steam for an existing or new steam turbine, to the replacement of virtually all of an existing generating unit (boiler, turbine and generator).

TABLE 5-8 (Continued)

Factor affecting cost:	Costs differ for new vs. existing site?	Factor Important in coal vs. gas decision?	Costs vary by region?	Costs vary by electric utility?
C. Operating & Maintenance (other than fuel):				
1. Key Variables				
a. O&M activities that must be performed which differ by fuel tupe	No	Yes	No	Possibly
b. Number of people required for operation	No	Yes	No	Possibly
2. Key elements of cost (O&M activities that must be performed)				
a. Wage rates	No	No	Yes	Possibly
b. Benefit costs & practices	No	No	Yes	Yes
c. Union or non-union	No	Yes	Yes	Yes
d. Insurance	Yes	Yes	Yes	No
D. Fuel				
1. Delivered Fuel Cost	Yes	Yes	Yes	Yes
a. In the case of coal				
1) Key variables:				
a) Type of coal that could be used (Sulfur, ash content, ash softening temp., etc.)	No	Yes	Yes	No
b) Competition among potential suppliers	No	Yes	Yes	No
c) Distance & transport alternatives from mine to generating plant (& competition among transporters)	No	Yes	Yes	No
2) Key elements of cost				
a) Cost of coal at mine mouth	No	Yes	Yes	Possibly
b) Cost of transportation (rail, ship or barge, conveyor and/or pipeline)	Yes	Yes	Yes	Possibly
b. In the case of natural gas:				
1) Key variables:				
a) Distance from nearest pipeline that can handle required volumes, pressures & variability	Yes	Yes	Yes	No
b) Distance from wellhead to generating unit	No	Yes	Yes	No
c) Number of pipelines involved				
d) Areas traversed by new or expanded pipeline (e.g., city streets, wetlands, rock)	No	Yes	Yes	No
e) Transportation firm or interruptible	No	Yes	Yes	No
f) Pipeline rate design	No	Yes	Yes	No
g) Backup fuel requirements and permissions to use	Yes	Yes	Yes	No
h) LDC involved in providing gas or transport?	No	Yes	Yes	No
i) Whether cross-subsidies are involved	No	Yes	Yes	No
j) Resolution of restructuring issues; e.g., allocation of costs, storage; penalties for variable takes, receipt & delivery points; brokering	No	Yes	Yes	No
2) Key cost elements				
a) Cost of gas at wellhead	No	Yes	Yes	No
b) Gas pipeline transportation costs:	No	Yes	Yes	No
i) If interruptible, full or discounted rate?				
ii) If firm:				
. Whether existing facilities are available at rates less than new capacity				
. Cost of new facilities, if needed (e.g., new pipe, looping, compresssion)				
. Rate design, including:				
. Whether costs are incremental or rolled-in				
. Split of costs between demand & commodity				
. Amortization period				
. Load factor				
iii) If LDC involved, "value of service," cost of service or negotiated rate				

TABLE 5-8 (Continued)

Factor affecting cost:	Costs differ for new vs. existing site?	Factor Important in coal vs. gas decision?	Costs vary by region?	Costs vary by electric utility?
D. Fuel (continued)				
1. Delivered Fuel Cost	Yes	Yes	Yes	Yes
b. In the case of natural gas:				
2) Key cost elements				
c) Cost of monitoring subsequent rate cases & other regulatory proceedings	No	Yes	Yes	No
d) Cost of managing fluctuartions in consumption rates & balancing receipts into each pipeline with deliveries from each pipeline; e.g., imbalance and variable take penalties (636 issues)	No	Yes	Yes	No
2. Fuel storage costs				
a. In case of gas				
1) Availability	No	Yes	Yes	No
2) Injection, withdrawl and storage charge	No	Yes	Yes	No
3) Inventory carrying cost	No	Yes	Yes	No
b. In case of coal				
1) Location, ownership of storage	No	Yes	Yes	No
2) Inventory carrying cost	No	Yes	Yes	No
3. Other possible fuel costs				
a. Coal: Freeze proofing, agent fees, dumping charges, broker fees, additives	No	Yes	Yes	No
b. Gas: broker fees	No	Yes	Yes	No
E. Environmental costs and waste disposal costs (which may be included above under O&M or fuel):				
1. Key variables				
a. Federal, state, and local requirements: air, water, solid & hazardous waste; e.g., in the case of air, in an attainment or nonattainment area	Yes	Yes	Yes	No
b. Neighbor and political leader attitudes towards plant	Yes	Yes	Yes	No
2. Key elements of cost:				
a. Air pollution equipment required	No	Yes	Yes	No
b. Water discharge control equipment, treatment, and fish protection requirements	No	Yes	Yes	No
c. Solid and hazardous waste disposal site requirements	No	Yes	Yes	No
1) In the case of coal:				
a) Coal ash	Yes	Yes	Yes	No
b) Sludge (if scrubber)	Yes	Yes	Yes	No
d. Costs or revenue from emissions trading (+ or -)	No	Yes	No	No
F. Plant efficiency; i.e., heat rate (BTUs to kw)	No	Yes	No	No
G. Subsidies available from Federal, state, or local governments; e.g.:				
1. Tax incentives for using indigenous fuel	No	Yes	Yes	No
2. Tax incentives for pollution control equipment	No	Yes	Yes	No
3. Federal or state research, development or demonstration subsidies	No	Yes	Yes	No
4. Federal or state low interest loans	No	Yes	Yes	No
5. Tax incentives for developing (or participating in development of) the fuel (e.g., coalbed methane)	No	Yes	Yes	No
H. State actions to encourage or requre use of indigenous coal				
I. Externality factors, if required by state IRP rules	No	Yes	Yes	No

ATTACHMENT #4

ADDITIONAL INFORMATION ABOUT THE ELECTRIC INDUSTRY THAT MAY BE USEFUL TO THOSE WHO WISH TO MARKET NATURAL GAS TO THE INDUSTRY

- **Key forces and developments affecting traditional electric utilities**
- **Electric utility planning process—to bring electricity demand and supply into balance**
- **Power pools and economic dispatch of generating units**
- **Common misunderstandings and misconceptions.**

The work of the Demand and Distribution Task Group revealed that some in the natural gas industry lack a good understanding of important developments and processes in the electric utility industry that affect potential markets for natural gas for electric generation. In fact, some misunderstandings may be impeding efforts to increase the contribution of natural gas in the generation of electricity.

The main body of this chapter provides information on potential electric generation demand for gas and includes information intended to help those who wish to market gas for electric generation.

This attachment provides additional information on the four topics listed above.

Key Forces and Developments Affecting the Electric Generation Industry

The electric utility industry, particularly the investor-owned segment, is subject to a number of forces and relatively new developments that affect individual companies' decisions, including decisions that affect generating capacity and fuel choices. This section identifies briefly several of those forces and developments.

Obligation to Provide Reliable Service at Lowest Possible Cost

Electric utilities generally have an exclusive franchise to provide electricity in a defined territory. That franchise carries with it an "obligation to serve" all customers in that territory, providing reliable service and doing so at lowest possible cost.

Regulatory Oversight

Investor-owned utilities (which provide about 78 percent of all the electricity used in the United States) are subject to regulations and oversight of state utility commissions and, in the case of wholesale transactions, by the Federal Energy Regulatory Commission.[30] Among other things, regulatory commissions approve rates charged to electric customers. As a part of their responsibility, regulatory commissions review the prudence of decisions made by the management of investor-owned utilities. Such reviews extend to all costs, including the cost of input energy used by the utility to generate electricity.

Obligations to Shareholders of Investor-Owned Utilities

Like investor-owned firms in other industries, the management of electric utilities also has an obligation to their shareholders—to provide a reasonable return on their investment and, hopefully, to increase the value of their stock holdings.

When a utility commission prevents recovery through rates charged to customers of any part of the cost that has been incurred by the utility, that cost is borne by the shareholders. Thus, the management of an electric utility is constantly faced with the responsibility of assuring that its actions are found to be prudent so that costs incurred—whether for capital, operations and maintenance, fuel or power purchases—can be recovered through rates paid by customers.

The activities of investor-owned electric utilities are open for scrutiny by customers and

[30] Public utility holding companies are also subject to regulatory authority of the U.S. Securities and Exchange Commission pursuant to the Public Utility Holding Company Act, as amended.

the general public—as well as by the commissioners.

Increased Competition

While once considered well-protected monopolies in their respective service territories, many traditional electric utilities are now facing competition in all phases of their business, including:

Generation. In the case of electric generation, utilities are experiencing competition from:

- Non-utility generators, including:
  - Cogenerators, including facilities that produce electricity and useful thermal energy for commercial, industrial, heating or cooling purposes.[31]
  - Small power producers, which include facilities of 80 megawatts or less getting more than 75 percent of their energy input from waste or renewable sources such as hydro, biomass, geothermal or solar sources.
  - Independent power producers (IPPs) that produce electricity and sell it on a wholesale basis to an electric utility for resale.
- Other electric utilities with excess capacity. Utilities often have excess capacity, at least at certain times, which they are prepared to sell at a market rate.

Transmission. Electric utilities are increasingly being encouraged (or required) to provide access to their transmission lines for movement of power generated by other utilities for sale on a wholesale basis to a third utility.

Distribution. Some legislators and regulators are proposing that electric utilities be required to make their transmission *and* distribution facilities available to permit movement of power from other utilities, small power producers or IPPs to end-use customers in their franchised territory ("retail wheeling").

End use. Most electric utilities have long faced competition at the point of energy use from other energy sources, including natural gas, petroleum or, in some cases, coal. More recently, utilities have seen competition at the point of use from conservation, with the measures to reduce electricity use provided by the end user or by a third party on a shared-savings basis.

Competition faced by electric customers. Commercial and industrial firms served by utilities within high or rapidly rising rates are making it clear to utilities that electricity costs—for the firm and their employees—are an important factor in business location, relocation, or expansion. In this sense, electric utilities may be competing in global markets.

Rising Costs and Rising Electric Rates

Like other firms, many electric utilities are facing rising costs. Higher costs, generally resulting in higher electric rates, are due to such factors as the cost of maintaining, renewing, or upgrading generation, transmission, and distribution facilities; meeting increasingly stringent environmental requirements; paying rising employee health benefit costs; booking of post-retirement health benefit costs; upgrading nuclear facilities to meet current standards and preparing to handle nuclear wastes; and/or paying for power purchased from others, including "qualifying facilities."

In the case of some electric utilities, rising costs during the 1980s were offset in significant part by declining fuel costs and rapidly increasing sales—so that the total costs per kilowatt hour paid by customers did not increase significantly. The potential for substantial downward adjustments in fuel costs to offset other cost is less now than in the early 1980s.

Integrated Resource Planning (IRP)

Electric utilities in more than 30 states must now comply with some kind of requirement to develop "Integrated Resource Plans."[32] IRP requirements are having a major impact and this impact is likely to increase; e.g.:

- Force changes in the way utilities plan and broaden the alternatives considered

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[31] Cogenerators meeting requirements established pursuant the Public Utility Regulatory Policies Act of 1978 enjoy certain benefits, including the right to sell excess electricity to electric utilities.

[32] IRPs are discussed in more detail in Appendix C at the end of this volume.

- Shift energy policy making and, in some cases, environmental policy making more to the state and regional level
- Broaden the focus of activities to conserve energy and achieve better utilization of resources to cover generation, transmission, and distribution of electricity and customers' end use of that electricity.

IRP requirements vary from state to state, but often:

- Require "least cost" planning, in the sense of requiring that reduction of electricity demand be considered along with increasing the supply of electricity.
- Establish cost to customers as the primary criteria for selecting the alternative that would bring electricity demand and supply into balance.
- Adopt an "all customer," "all utility," or "societal" test for measuring cost to customers—rather than requiring that no customer would pay more (the so-called "no losers test"). The net effect is that public utility commissions are allowing subsidies to encourage electricity conservation and efficiency—even if the cost of the subsidies are borne by other customers, customer sectors, or generations than those who benefit from the subsidy.
- Include requirements extending beyond the narrower concept of "least-cost planning."
- Increase the focus on potential ways to increase energy efficiency in all customer categories and on energy conservation measures not previously recognized as more cost beneficial than building new generating capacity (e.g., more energy efficient building design and building materials; more energy efficient industrial processes).
- Require use of competitive bidding to help identify economical supply and/or demand-side alternatives.
- Increase focus on the potential for reducing losses in their transmission and distribution systems (e.g., replacing transformers and cable to reduce losses).
- Adopt, in a growing number of states, "environmental externality" requirements that tend to increase the calculated cost of supply-side measures compared to reduction in demand.
- Open the electric utility planning process to additional public scrutiny and participation by intervenors, including competitors to the electric utilities.

In addition, some states are adopting incentives for electric utilities, along with IRP requirements, that are designed to make "demand-side" activities at least as profitable as selling electricity.

Electric and Magnetic Fields (EMF)

The relatively recent concerns that have emerged concerning potential health effects of EMF has added a new uncertainty for electric utilities. Electric and magnetic fields are associated with various aspects of electric generation, transmission, distribution, and use.

Concerns about potential health effects of EMF have led to or provided a new basis for opposition to proposals for new or expanded transmission lines even though EMF measurements may be higher from an electric blanket, hair dryer, or clock than from a transmission line. (EMF measurements decline sharply with distance from the line or appliance.)

Extensive research has been undertaken by the electric utility industry and government agencies that should shed more light on outstanding questions.

To date, it appears that scientific evidence may not justify the health concerns that some have expressed. However, the electric utility industry is working to deal with these concerns.

Finding and Getting Approval for Sites and Rights-Of-Way

In some regions of the country, traditional electric utilities and independent power producers are facing considerable difficulty in finding and getting approval for sites for new generating facilities and rights-of-way for transmission lines and other facilities (water supplies, waste sites, etc.) need for new facilities. Generally, dozens of permits are required and opposition is common from people concerned about potential environmental impact or, often, about having a facility or line near their property.

The Electric Utility Planning Process—To Bring Future Demand and Supply into Balance, and to Provide Diversity and Flexibility in Energy Sources

Those seeking to market natural gas for electric generation should have a basic understanding of the planning process followed by electric utilities as they seek a reasonable balance between future electricity demand and supply, and pursue other operational objectives. Following is a discussion of the steps included in the process.

Estimating Future Peak Load Demands for Electricity (Kilowatts)

Estimating future peak loads (generally over the ensuing 10 years) is important because electric utilities' obligation to serve is generally interpreted to mean providing electricity upon demand from all customers except those with whom special interruptible service has been arranged.[33] The utility compares estimated peak demand, plus a reserve margin (to allow for unexpected generating unit outages) to the generating capacity owned by the company, and capacity available under the company's contracts with other utilities and non-utility generators.

Evaluating Alternative Ways to Supply Estimated Demand

If the capacity is inadequate the utility will consider:

- Measures to reduce peak demand ("demand-side")
- Buying additional capacity under contract from other utilities or non-utility generators
- Increasing its own generating capacity.

[33] Utilities may have arrangements with certain industrial customers that give the utility the right to interrupt electricity supplies if generating capacity proves inadequate (e.g., in mid-afternoon on a hot summer weekday for a summer-peaking utility)—in exchange for an "interruptible" rate that is lower than that charged other customers in the same rate class.

Actions to increase the utility's own generating capacity may include:

- Capital or maintenance spending to:
  - Extend the life of a generating unit that otherwise had been planned for retirement during the planning period or
  - Increase the availability of existing generating units (i.e., avoid unit downtime).
- "Repowering" and increasing the capacity of an existing unit.
- Adding a new generating unit at an existing site.
- Building a new generating unit at a new site.

The approach selected to bring estimated future demand and supply into balance will depend on:

- The type and duration of the expected demand. For example, a peak that is expected to occur for only a few hours on a few days might be met by building a "peaking" unit, or by finding more customers willing to accept interruptible service and rates
- In the final analysis, the alternative with the lowest cost to customers.

If capacity is expected to exceed peak demand, the utility will consider such measures as selling the capacity to other utilities or retiring or mothballing one or more generating units.

An electric utility may not plan capacity to meet *all* of its expected peak if it concludes that power will be available on the very active "spot" market that exists wherein utilities buy and sell power on a short-term (perhaps only a few hours) basis from or to utilities that are reachable with transmission capacity available in the region.

Estimating Total Electricity Usage (Kilowatt Hours)

Electric utilities also estimate the total amount of electricity (kilowatt hours) that they expect customers to require. These estimates are used for a wide variety of planning purposes, including estimates of which generating units will be run for what periods of time, the quantities of fuel that will be needed for those units, and scheduling outages for generating unit maintenance and capital improvements.

Pursuing Diversity in Energy Sources and Flexibility in Energy Mix

Most electric utilities have learned that energy markets are quite unpredictable and market forecasts are often wrong. They have also learned that too heavy reliance on any one energy source can leave them short of capacity if the energy source is unavailable or facing high cost if the energy source increases sharply in price (as in the case of oil in 1973-74 and 1979-80).

Accordingly, many electric utilities attempt to have a mix of energy sources. In addition, many electric utilities work to have a mix of suppliers and transporters for the fuels that they do use so that their customers have the benefit of lower fuel costs that generally results from competition among suppliers and transporters.

Power Pools and Economic Dispatch of Generating Units

The majority of the electric utilities in the United States are a part of a "*power pool*." The role of power pools is important to those wishing to sell gas to the electric utility industry since the operation of power pools has an impact on the need for generating capacity and on which of available generating units is actually used.

Most power pools are made up by a group of electric utilities serving a particular region or possibly a state (e.g., the New England Power Pool or the New York Power Pool) that voluntarily agree to join together for certain purposes. Those purposes generally include such activities as:

- Planning
- Scheduling of generating unit and transmission lines for downtime (i.e., for maintenance or construction activities)
- Most important for this report, the economies of:
  - Economic "dispatch" (i.e., bringing on-line, taking off-line, and the amount of load that a unit is called upon to supply)
  - Sharing reserve margins and improving reliability.

Utilities that are a part of a power pool, in effect, turn over to the power pool the responsibility for determining which generating units are run at which times—just as if all the generating units were owned by a single organization.

As indicated in Chapter Six, "base load" units are generally kept running most of the time that they are available. However, they may run at less than full capacity. If base load units run at less than capacity (perhaps in the middle of the night) and customers increase their demand for electricity, dispatchers operating on behalf of the power pool increase the output from the base load units (perhaps by increasing the fuel input). As demand for electricity continues to increase, "cycling" or intermediate load units are brought on-line. And if demand continues to grow (perhaps on a hot weekday afternoon in August!), "peaking" units are brought on-line.

As demand subsides, peaking and then cycling units are taken off-line and, eventually, base load units are run at a lower level of output.

The *incremental* cost of producing electricity from a generating unit is, in general, the governing factor used by dispatchers in determining which unit to bring on-line or take off-line. The underlying objective is to run the lowest incremental cost units first and the highest incremental cost units last. The concept is "*economic dispatch*" of generating units.

Incremental cost is the difference in the cost of producing electricity from a generating unit when it is being run and not run. It consists primarily of *fuel cost*. Thus, hydro and nuclear units are generally dispatched first, followed by coal-fired units and then, depending upon incremental fuel costs, oil- and natural gas-fired units. The relative efficiency with which a generating unit converts the energy input into electricity output ("heat rate" in the case of steam and gas turbine units) is also a part of the equation used in determining the incremental cost of producing electricity from a unit.

Savings resulting from dispatching the lowest incremental cost units first are then shared among the utility whose customers need the electricity and the utility owning the generating unit that was run to serve the electricity load.

Misunderstandings and Misconceptions About the Electric Utility Industry

Improved communications among organizations in the electric utility and gas industries appears to be impeded by a number of misunderstandings and misconceptions about electric utilities' motives, policies and practices. These are important because they appear to be standing in the way of productive efforts by gas producers, marketers, and pipelines that might lead to increased use of gas in electric generation.

The misconceptions are unlikely to be overcome until direct communications improve. Several efforts now underway to improve communications between the gas and electric industries should help overcome these misunderstandings.[34]

"Electric utilities choose coal rather than natural gas because they prefer high capital cost generating facilities"

The logic for this assertion is that utilities building high capital cost generating facilities have a higher "rate base" upon which to earn a return for their shareholders. However, those believing this assertion seem to overlook several important considerations; e.g.:

- Most electric utilities have substantial needs for capital investments in upgrading their generating facilities and expanding and upgrading their transmission and distribution systems and have no interest in avoidable capital spending.
- Investor-owned utilities are subject to oversight, and utility commissions are well known for their scrutiny of capital investments and for testing whether facilities are "used and useful."
- The regulatory oversight process, particularly with the emergence of Integrated Resource Plans, provides considerable opportunity for review by the public, customers, and the commissions.

Confusing the terms "Rate Base" and "Base Rates"

Outside regulated utilities, the terms "rate base" and "base rates" are often confused—leading to assertions that utilities increase their *earnings* by increasing their *expenditures* (e.g., for advertising). In fact, the two phrases have substantially different meanings:[35]

- Base Rate refers to: "That portion of the total electric rate covering the general costs of doing business unrelated to fuel expenses."
- Rate Base refers to: "The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return. Generally, this represents the amount of property used and useful in public service and may be based on the following values or combinations thereof: fair value, prudent investment, reproduction cost, or original cost; and may provide for the inclusion of cash working capital, Construction Work in Progress, Materials and Supplies, and deductions for: Accumulated Provision for Depreciation, Customer Advances for Construction, and Accumulated Deferred Income Taxes and Accumulated Deferred Investment Tax Credits."

If one is referring to the base upon which earnings are set by a regulatory authority, the correct phrase is "Rate Base."

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[34] The Interstate Natural Gas Association of American has created a Power Generation Task Force that is working to improve direct communication among senior people from the gas and electric generation industries. The Gas Committee of the National Association of Regulatory Utility Commissioners and the U.S. Department of Energy have sponsored at least one conference where representatives of the two industries, along with State and Federal regulators, have met to share information and views. The Electric Power Research Institute has recently published a report on a study of the need for coordination between the gas and electric industries. The Edison Electric Institute has cosponsored forums over several years with the American Gas Association to improve dialogue between the industries and held conferences with the Institute for Gas Technology and Canadian producers.

[35] These specific definitions are taken from the "Glossary of Electric Utility Terms," prepared by the Statistical Committee of the Edison Electric Institute, July 1991.

"The electric utility industry has a 'coal bias'"

This assertion appears to be based on some facts and some misconceptions; for example, it is quite true that:

- Coal provides a larger share of energy for electric generation than gas and that coal remains a serious competitor to gas in the electric generation market in large areas of the United States (which will be discussed in more detail below).
- Coal producers and transporters (railroads, ship and barge owners, and truckers) have considerably more experience in marketing coal directly to electric utilities than do gas producers. Coal producers and railroads often have whole departments focused on understanding of and selling to electric utilities in their market areas.
- Electric generators are motivated by concerns about reliability and coal is perceived as reliable.
- Some generating plant managers are much more comfortable with having an inventory of fuel on site and under their control—which is very practical in the case of oil and coal, rather than a connection to a pipeline and a supply of fuel that is under someone else's control.
- Major generation capacity expansion was accomplished when large central station power plants were in vogue and gas was perceived to be in short supply.

Other bases cited for the "coal bias" assertion appear to be misunderstandings; for example:

- The alleged "preference for high capital cost generating facilities"
- The higher share of gas-fired generation units planned by independent power producers compared to the share among units planned by traditional electric utilities. This difference appears explained in large part by four factors:
  - The different financial structure used by IPPs to finance their facilities.
  - Different obligations to serve.
  - Many of the coal-fired units planned by traditional electric utilities are at existing coal-fired generating stations.
  - Many of the planned IPP projects are at new sites, and in regions of the country that are less receptive to coal-fired projects or where gas transportation costs are relatively low.

"Electric utilities are not (or should not be) concerned about fuel costs because these are automatically passed through to customers"

It is true that, in some jurisdictions, fuel costs are fully "passed through" to customers on a relatively current basis and are not reviewed by regulators at the same time as the review of base rates.[36] However, the assertion misses the point that:

- Electric utilities have an obligation to procure fuel at the lowest possible delivered cost.
- Fuel costs are a part of the total bill paid by electric customers and any utility that does not work to hold down its fuel costs is asking for trouble from its customers, its regulators and its competitors.
- The reasonableness of fuel costs is subject to after-the-fact review and disallowance without statute of limitations protection.

"Since it takes 'X' years to build a coal plant, utilities will have no choice, when electricity demand increases, but to build a gas-fired generating unit if they don't already have a coal-fired unit under construction"

Construction time for a coal-fired generating unit *at a new ("greenfield") site* would probably take longer than construction of a comparable size gas-fired combined-cycle generating unit. Also, depending upon the area, it may be more difficult and take longer to obtain all the necessary permits for the coal-fired unit. However, this generalization does

[36] This practice has been used quite widely since fuel prices became particularly volatile following the 1973 oil price shock.

not take into account some very practical considerations, including:

- The utility involved may have room at an existing coal-fired generating station to add another coal-fired unit that could be built much more quickly.
- A utility often has alternatives available to delay the time when it must have new generating capacity available. Those alternatives may include:
  - Investing capital or maintenance dollars to increase the availability, extend the life or delay the planned retirement of an existing generating unit
  - Buying a partial interest in a generating unit being built by another utility or an independent power producer
  - Buying sufficient power to cover the period until a new unit can be brought online from another utility or an IPP.

In fact, these alternatives may be preferable to smooth the transition to the time when new generation is required.

CHAPTER SIX
NATURAL GAS VEHICLES

The use of compressed natural gas (CNG) as an alternative vehicle fuel in the United States presents an excellent opportunity for growth for natural gas marketers. Interest in clean-burning alternative fuels has been stimulated by the Clean Air Act Amendments of 1990 (CAAA'90) and the recently enacted Energy Policy Act of 1992.

BACKGROUND

Few Americans have ever seen a natural gas vehicle (NGV), let alone driven or owned one. Other nations have been driving NGVs since World War II, when severe petroleum shortages curtailed gasoline production. Today almost half (about 300,000) of the world's 700,000 NGVs are found in Italy. By contrast, just 32,000 NGVs can be found on our roads; scarcely 0.01 percent of the total 180-190 million vehicles in this country. In its early years, the U.S. automobile industry experimented with using natural gas and other alternatives as a vehicle fuel. But, as petroleum products became increasingly plentiful, accessible, and inexpensive, natural gas and other fuels were for the most part pushed aside. Thus our transportation systems became petroleum-based (predominantly gasoline and diesel fuel). Two oil embargoes and several price spikes later, petroleum prices and security of supply are still major issues along with the more long-term concern of the environmental problems associated with tailpipe emissions.

There are a number of alternatives to gasoline. Among them are methanol, ethanol, liquefied petroleum gas, liquefied natural gas, solar energy, electricity, and natural gas. Now, and in the future, these alternatives must compete with each other and with the several reformulations of gasoline currently being tested. The relative success of these alternatives depends on numerous factors, including safety, automobile performance, the ability to adapt the distribution and marketing system, environmental impacts, economics of both fuel and vehicle, public acceptance, and technology change.

Throughout the 1970s and the 1980s the federal government, largely under the auspices of the U.S. Departments of Energy and Transportation, developed alternative fuel research programs, primarily emphasizing methanol, ethanol, and electric cars. Currently, however, the CAAA'90 provides a market stimulus for alternative fuels. Among other things, the Amendments mandate that, in the 22 cities where ozone is most serious (see Table 6-1), fleets of 10 or more vehicles must begin purchasing clean-burning vehicles by model year 1998. Thirty percent of new centrally fueled light duty vehicles (those below 3,750 pounds gross vehicle weight) and 50 percent of the new trucks (up to 26,000 pounds gross vehicle weight) will be required to operate on clean-burning alternative fuels. Further, strict new emission standards for both public (government) and private (commercial/industrial) fleet vehicles will encourage clean fuel technologies.

TABLE 6-1

22 METROPOLITAN AREAS AFFECTED BY THE CLEAN AIR ACT AMENDMENTS CLEAN-FUEL FLEET PROGRAM (NONATTAINMENT AREAS)

Metropolitan Area	Environmental Criteria*	1980 Population (1,000)	1990 Population (1,000)
Atlanta, GA	3	2,138	2,833
Bakersfield, CA	3	403	543
Baltimore, MD	2	2,199	2,382
Baton Rouge, LA	3	494	528
Beaumount, TX	3	373	364
Boston, MA (CMSA)	3	3,972	3,783
Chicago/Gary, IL/IN	2	7,937	8,065
Denver/Boulder, CO	4	1,618	1,848
El Paso, TX	3	480	591
Fresno, CA	3	515	667
Hartford, CT (CMSA)	3	1,014	1,123
Houston/Galveston, TX	2	3,100	3,711
Huntington/Ashland, WV/KY/OH	3	336	322
Los Angeles, CA (CMSA)	1,4	11,498	14,531
Milwaukee/Racine, WI	2	1,570	1,607
New York, NY/NJ (CMSA)	2	17,540	17,953
Philadelphia, PA/NJ/DE (CMSA)	2	5,641	5,899
Providence, RI (CMSA)	3	1,083	916
Sacramento, CA	3	1,100	1,481
San Diego, CA	2	1,862	2,498
Springfield, MA	3	515	602
Washington, DC/MD/VA	3	2,350	3,923

* 1=Extreme Ozone Nonattainment; 2=Severe Ozone Nonattainment; 3=Serious Ozone Nonattainment; 4=Carbon Monoxide > 16.0 ppm.

NGVs are expected to compete effectively with other clean fuels in this new environment.

POTENTIAL MARKET

As a result of the CAAA'90, the transportation sector can be expected to increase its consumption of natural gas. Specifically, Title II of the Act contains provisions affecting virtually every type of vehicle in the nation's transportation system, as the legislation calls for more stringent emission standards beginning in 1994 for conventional and diesel-powered vehicles. This regulation provides the natural gas industry with a substantial opportunity to promote its compressed natural gas technology and to assist NGVs in overcoming existing constraints. Fleet operators who buy more or cleaner vehicles than required by the CAAA'90, or earlier than specified, will be given tradable credits that can be saved or sold to other fleets within the same nonattainment area.

There are an estimated 30 million fleet vehicles in the United States, over one-third of these are located in Nonattainment Areas (see Table 6-1). In 1990 there were nearly 17.6 million automobiles and trucks up to 26,000 pounds. Of these, an estimated 9.7 million were in fleet applications that are considered to be highly compatible with CNG as a vehicle fuel (Table 6-2). Urban transit and school buses, taxis, delivery trucks and vans all fall within the fleet category. By 1999 the percentage of new purchases will increase to 50 percent and grow to 70 percent in 2000 and beyond. Recent estimates indicate that federal and state initiatives will require 1.3 million vehicles to run on clean fuels by the end of the decade. In this changing environment, NGVs are anticipated to be in a good competitive position to gain market share. Current EIA data shows that only 0.4 billion cubic feet (BCF) of natural gas was consumed for vehicle fuel in 1991. Several projections have been released recently that have NGV consumption increasing to nearly 200 BCF annually by the year 2000, or nearly 1 percent of a projected total natural gas consumption of 21.9 trillion cubic feet (TCF) in 2000 according to the U.S. Energy Information Administration's (EIA) most recent forecast. Other projections are not as optimistic; the NPC's own model suggests a market of 50 BCF by the year 2000 rising to 140 BCF in 2010, while the Gas Research Institute's natural gas consumption estimate for NGVs contains 179 BCF by 2000 and 497 BCF in the year 2010.

There are also about 58,000 public transit buses operating in U.S. cities. In large metropolitan areas, there is an average of 250 transit buses per million people. On this basis, there would be about 31,700 buses in metropolitan areas with populations greater than 750,000. These buses could be required to use clean-burning alternative fuels if they are unable to meet or maintain strict 1994 particulate emission standards with diesel technology. Many of these vehicles and diesel powered locomotives are prime candidates for the use of liquefied natural gas (LNG) in order to meet alternative fuel requirements. Several tests and research efforts are underway to best adapt LNG to diesel motors.

Legislative Impetus

In addition to the already defined requirements of the CAAA'90, the Energy Policy Act of 1992 (EPACT) contains alternative fuel requirements. This legislation, primarily a by-product of the Department of Energy's National Energy Strategy, has specific requirements and timetables, along with either subsidies, tax incentives, or research and demonstration funds to promote alternative fuel use.

Examples:

- EPACT promotes greater use of clean-burning natural gas by expediting licensing procedures for construction of

TABLE 6-2

1990 FLEET VEHICLE STOCK AND AFFECTED-AREA SALES (1,000 VEHICLES)

Fleet Vehicle Type	Total U.S. Stock*	Compressed Natural Gas-Compatible Stock†	Total U.S. Sales	Nonattainment Area 1990 Sales: U.S. Except CA	Nonattainment Area 1990 Sales: CA	Sales in Calif. Attainment Areas
Automobiles	10,592	5273	221.0	51.9	16.4	8.4
Light-Duty Trucks	2,985	2,985	378.1	86.9	28.6	14.7
Medium-Duty Trucks	1,155	733	8.7	2.1	0.7	0.3
Heavy-Duty Trucks	2,913	718	53.1	12.3	4.1	2.1
Total	**17,645**	**9,709**	**660.9**	**153.2**	**49.8**	**25.5**

* In fleets of 10 or more vehicles (from *1990 Fleet Fact Book*).

† Not exempt, centrally fueled, and travel less than 90 miles/day.

NOTE: Certain fleets are exempt from the regulation, including rental vehicles, law enforcement and emergency vehicles, and vehicles held for sale.

interstate gas pipelines, facilitating gas producers' market access, and eliminating regulatory barriers to greater use of natural gas in motor vehicles.

- EPACT calls for the development and use of clean-burning alternative motor fuels by: requiring government and large private fleets to use alternative fuels; setting up electric and electric-hybrid vehicle demonstration programs; and providing financial support for demonstrations of alternative fuel use by urban mass transit systems.

- EPACT requires DOE to (1) publish a list of all private and government alternative fueling facilities that are or could be made available to the public, and (2) require, before 1/1/93, any organization regulated under state law as a natural gas utility and any interstate natural gas pipeline company to make their alternative fueling facilities available to the public.

- EPACT promotes state and local incentives programs and authorizes DOE to provide information, technical assistance, and financial assistance to states to implement plans for ensuring that substantial numbers of alternative fuel vehicles are in use by 2000.

- Federal Fleets. Requires the federal government to acquire 5,000 alternative fuel vehicles in 1993, 7,500 in 1994, and 10,000 in 1995. Beginning in 1996, a minimum percentage of the vehicles acquired in any year by each federal agency, including the Congress, must be alternative fuel vehicles. By 2000, nine out of every ten fleet vehicles acquired by a federal agency must be alternative fuel vehicles. The federal government excluding the Defense Department purchases approximately 50,000 new vehicles a year.

- State Fleets. Requires states that have at least 50 fleet vehicles statewide and at least one fleet of 20 or more vehicles in a metropolitan statistical area with a 1980 Census population of 250,000 or more to begin acquiring alternative fuel vehicles for fleets in such areas beginning in 1995. By 2000, nine out of every ten fleet vehicles acquired by a state for use in such areas must be alternative fuel vehicles.

- Incentives. Requires states to consider adopting measures to promote the use of alternative fuel vehicles and to report to the Secretary of Energy on measures considered or adopted.

- School Bus Funding. Authorizes the Secretary of Energy to provide financial assistance to States and municipalities to help pay the incremental cost of buying and using alternative fuel school buses.

The Natural Gas Vehicle Coalition (NGVC) estimates that if the entire 30 million fleet vehicles now operating in the U.S. switched to natural gas, an additional 2 TCF would be required per year. Admittedly these are ambitious and some may say unrealistic estimates, but they do serve the purpose of defining an area of great market potential.

Several attributes may make CNG the fuel of choice for fleet usage. Gasoline-powered engines can be converted relatively easily and pre-1988 conversions may be applied as credits to meet the 1998 CAAA'90 clean-fuel fleet requirements. CNG fueled vehicles are the cleanest alternative fuel (at the tailpipe), after electric powered vehicles, generating up to 75 percent less carbon monoxide than oxygenated gasoline. Natural gas generally appeals to notions of U.S. energy security in light of ready access to both domestic and North American (Canadian) supplies.

Natural gas consumption as a vehicle fuel to reduce emissions is likely to face extreme competition from liquid alternatives to conventional gasoline. In response to the CAAA'90, oil companies are working on ways to reformulate current fuels and gasoline to reduce harmful emissions. Many are beginning to test a series of fuels. The new fuels will include a reformulated diesel, a methanol mix, and unleaded gasolines. The first phase of the program began in Southern California where ARCO marketed a motor gasoline and new diesel fuel at selected area service stations. The fuel is intended to meet stricter Environmental Protection Agency standards scheduled to take effect in 1993 in Southern California, Los Angeles, and San Diego, and in 1995 in seven other selected metropolitan areas (Table 6-3).

TABLE 6-3

SERIOUS OZONE NONATTAINMENT AREAS

Metropolitan Area or Consolidated Metropolitan Area	Ozone Nonattainment Classification
Los Angeles-Anaheim-Riverside, CA	Extreme
Houston-Galveston-Brazoria, TX	Severe
New York City-New Jersey-Long Island, NY-NJ-CT	Severe
Baltimore, MD	Severe
Chicago-Gary-Lake Co., IL-IN-WI	Severe
San Diego, CA	Severe
Philadelphia-Wilmington-Trenton, PA-NJ-DE-MD	Severe
Milwaukee-Racine, WI	Severe
Hartford-New Britain-Middletown, CT	Severe

OBSTACLES TO GROWTH OF NGVS

In the real world of the U.S. marketplace, in order for natural gas to increase its use as a vehicular fuel by the year 2010 the natural gas industry must overcome several obstacles. Among these are infrastructure, vehicle availability and use, safety, and market growth strategies.

Infrastructure

The widespread use of CNG as a transportation fuel would require expansion of the current natural gas delivery infrastructure, largely through the addition of refueling stations.

The approximately 32,000 CNG vehicles in use in the United States are supported by a network of 530 private refueling stations located in 48 states. However, less than 200 of these stations offer CNG for sale to the general public and some of these by appointment only. The current 530 refueling stations represents a 50 percent increase over the number operating in 1990 and according to the NGVC, the number of stations offering CNG should continue to grow in 1993.

There are two basic types of CNG refueling stations: slow-fill and fast-fill. The slow-fill station uses a compressor and little or no storage capacity to refuel vehicles. Slow-fill stations are typically used for fleet operations where vehicles are idle in a single location for several hours, usually overnight. Initial capital cost for slow-fill stations is typically lower than fast-fill stations.

A fast-fill CNG refueling station is basically the same as a slow-fill station except that underground storage capacity is added to allow refueling in a very short time similar to a gasoline refueling station. The compressor in fast-fill stations must be sized to handle peak vehicle refueling demand without falling behind. These output requirements do require significant capital costs, usually totaling \$200,000 to \$300,000.

Most natural gas vehicles currently in use suffer from having a limited range of between 100 and 200 miles. This characteristic makes the need for an increase in number and accessibility of refueling facilities critical to the expanded use of NGVs. The American automotive consumer will demand the same dependability, convenience, and flexibility that they have come to expect from gasoline powered vehicles. Along these lines the Governors of LA, NM, AR, OK, KS, and AZ accepted Texas Governor Ann Richards's invitation and formerly agreed to work on a proposal to create an interstate fueling network for natural gas vehicles. CA, UT, NV, and CO also have been invited to participate. The initial effort will be on Interstate 10, which is being dubbed the "natural gas highway" and runs from Lake Charles, LA to San Bernardino, CA covering almost 2100 miles.

Vehicle Availability and Use

A key factor in promoting the increase of NGV refueling infrastructure is to increase the number of NGVs in use. Some have described this as the "chicken and egg" problem because it is unclear which comes first, the refueling stations or the NGVs. The majority of the NGVs currently in use in the United States are conventional gasoline or diesel engines that have been retrofitted to run on CNG.

The current cost of retrofitting a passenger car for dual-fuel use ranges from $2,000 to $4,000. Conversion prices are highly dependent upon the type of conversion equipment selected, and the number and type of storage cylinders placed on the vehicle. CNG cylinders increase in price as their dimension (storage capacity) and service pressures increase. Cylinder prices also vary by cylinder material; conventional steel is the least expensive, followed by composite steel and composite aluminum.

The big three auto makers appear to getting actively involved:

- A consortium of Western natural-gas utilities is providing $1.7 million to fund in part the production of fleet NGVs, which will be sold through selected General Motors Company (GMC) dealers in California, Colorado, and Texas. The dealers plan to emphasize sales to commercial fleets and the goal is to deliver over 2,000 vehicles by 1995. The vehicles will be warranted and serviced by the GMC Truck division.
- Chrysler Corporation will build a total of 600 1992 and 1993-model year passenger vans that run on natural gas for the General Services Administration (GSA). Those vehicles are part of a project sponsored by GSA and the Department of Energy.
- This year, Ford Motor Company will build a demonstration fleet of 100 CNG pickup trucks. Another 200 to 600 unit fleet is scheduled for 1993. These steps follow a five-year field-test program of 27 CNG Ranger pickups produced in 1986.

Initial growth in the number of vehicles will most likely continue to come through the retrofit and dual fuel vehicle conversion procedure. Several efforts are underway to promote converting vehicles to use CNG. One of the most active participants in this effort is T. Boone Pickens, whose Mesa Energy Group recently purchased a majority interest in Cleanfuels, Inc., a natural gas fuel system manufacturer. Earlier this year Mesa began offering to convert fleet vehicles in the Phoenix, Arizona area at no cost if the operator agreed to a long-term natural gas purchase contract. In the regulatory area, in July the Federal Energy Regulatory Commission (FERC) signed a rule to boost the use of natural gas as a vehicular fuel. The FERC rule automatically authorizes limited blanket certificates for CNG sales for resale. It states that sellers of CNG would not jeopardize their current regulatory classification, i.e., Hinshaw exemptions.

Safety

Many state and local safety officials view natural gas in a guarded and cautious sense. Detailed accident data for NGVs are sparse. Within the existing data, few fire and explosion accidents have been reported. A recent study in New York concluded that NGVs are even safer than gasoline powered vehicles and, consequently, the majority of New York state bridge and tunnel restrictions were removed. New fuel cylinder technology is state of the art, and in addition to reducing the weight of the storage units they have performed extremely well in several controlled tests. The majority of data on the subject conclude that nothing should preclude the safe use of NGVs. An additional benefit of the new cylinder technology is a significant increase in the useful life of the equipment to over 50 years under normal use with periodic inspections.

Market Growth Strategies

In the near term (1993-98) the market for compressed natural gas in fleet vehicle applications appears to be the most advantageous. This segment of the vehicle market is directly impacted by the CAAA'90, the EPACT, and the California Low Emission Vehicle Regulations (CLEV). Several other states—primarily in the Northeast—have taken steps to adopt similar standards (CLEV) and timetables. This approach also goes a long way toward building a refueling infrastructure: fleet vehicles return to the same location at the end of a normal workday, reliable data on fuel needs can be developed and maintained, and numerous vehicles can be refueled at one location by either fast or slow fill applications. This segment of the potential market will also be best equipped and predisposed to absorbing the initial costs in converting to CNG powered vehicles. In most cases, a fleet vehicle operator should be in the position to acquire the natural gas service at a competitive rate for their market area. This competitive rate coupled with the existing rules that allow CNG to be sold as a motor fuel without imposing road use taxes, which can range from 25 to 40 cents a gallon of gasoline, gives CNG the distinct competitive advantage that is needed during the phase-in period. In addition to marketing strategies, several industry-wide programs should be initiated and developed. These should include working with auto manufacturers to support NGV development, increasing refueling facilities, and encouraging all segments of the natural gas industry to become leaders in the use of NGVs.

CHAPTER SEVEN
TECHNOLOGY REPORT

CURRENT STATUS

Natural gas is increasingly seen as the fuel of the future, not only in the United States but throughout most of the populated world. There are a number of reasons for this view. The world reserve of natural gas recoverable by conventional technology is plentiful for the foreseeable future. Thus, this clean energy resource will remain competitively priced. Total world reserves that will be available via new production technologies are estimated to be many times the presently recoverable reserves, so the long-term potential is assured.

In the United States, a large natural gas resource exists so that it is seen as a secure source of energy, safe from the political unrest around the world. Extended consumption of natural gas will contribute to a positive balance of trade and jobs in the United States, as opposed to imported oil energy. The positive environmental benefits associated with natural gas—it is the most environmentally clean fossil fuel available—represent a major justification for national policies enhancing and encouraging its consumption.

The future for natural gas is bright. However, for natural gas to fulfill its role in the U.S. energy picture, the technologies related to its distribution and end use must continue to evolve. Today, the technologies required to capture the total benefit of natural gas are not in place. Further, efforts underway are not sufficient for natural gas to reach its potential in the national energy mix in a timely fashion. A robust research, development, and demonstration (RD&D) program is required and the current collective efforts to provide such a program are inadequate. An even more serious problem is a history of minimal commercialization and marketing efforts aimed at implementing the successful RD&D results.

As an overview of the RD&D efforts, Table 7-1 summarizes the funding estimated for 1992.

The shortcomings of this funding, as well as other related issues, are discussed at length in the NPC Focus Group Report, *Understanding Barriers to and Opportunities for Increasing Natural Gas Consumption*, (see Appendix C of Volume V). That report concludes that the gas industry must improve its ability to commercialize its new technology. To accomplish that goal requires that: the role of RD&D be recognized and adequate support provided; the industry become market-driven; the needs of customers receive primary attention; and regulatory bodies encourage rather than discourage the above.

OPPORTUNITIES AND NEEDS

The markets for natural gas can be classified as being for new or existing applications. The existing market is well-established, the benefits are easily definable, and a portion of the RD&D funds discussed earlier are generally directed toward those markets. However, the major concern is with new markets that

TABLE 7-1

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**

need innovative RD&D and commercialization efforts.

The major new markets for natural gas now being explored are natural gas powered vehicles (NGVs), cooling, power generation, and selected industrial applications. Each of these specific markets offers environment and efficiency benefits, but each also benefits gas company operations in that they tend to improve annual gas load factors; i.e., they balance the summer to winter delivery requirements, increasing overall delivery efficiency. Similarly, gas heat pumps and commercial applications provide these benefits, although their overall market potential may be smaller.

As discussed in Chapter Six, the NGV market is a potentially large market for natural gas. Presently, only a fraction of one percent of the vehicles in the United States operates on natural gas and most of these are utility-owned and operated vehicles. Major obstacles to the successful marketing of natural gas vehicles include the lack of a fueling infrastructure and the development of a complete line of natural gas-specific engines. Annual RD&D funding in NGVs is estimated to be in the range of $25 to $50 million, equally split between the gas industry and the engine/equipment manufacturers.

The power generation market is another potentially large market for natural gas, as discussed in Chapter Five. Approximately 25 quadrillion BTU of energy inputs are required annually for power production. Natural gas now supplies only about 10 percent of that total, down from almost 25 percent in the early 1970s. Major opportunities for new gas technologies include fuel cells, cogeneration units, combined-cycle power units, and reburning/post-combustion systems using natural gas. Due to the very high cost of developing, evaluating, and demonstrating these technologies, RD&D and commercialization funding falls very short of those needed.

Natural gas cooling is a lesser market than those mentioned above; however, it currently has nearly zero penetration. Its development suffers from a common problem to gas appliances, the lack of incentive for "fuel neutral" manufacturers to make the investment required to introduce new equipment. This is especially true as appliance manufacturers are traditionally low margin companies and cannot invest meaningful RD&D funds.

In the industrial sector, selected markets currently do not have gas technology as an option. These markets are very diverse and often very specific in terms of the technologies required. As in the appliance area, the equipment manufacturers are "fuel neutral" and financially weak. Industry drives are tending toward quality and convenience issues often at the expense of efficiency. Overall, the industrial sector consumes about 25 quadrillion BTU of energy annually with gas providing about 35 percent of that total.

The RD&D resources brought to bear on the existing applications are primarily Gas Research Institute (GRI) funds and industry funds, although manufacturers are participating in RD&D. As mentioned earlier, however, many equipment manufacturers do not have the financial or manpower resources to introduce newer concepts and technologies. Incremental improvements are typical. Also, as mentioned, the equipment manufacturers are fuel neutral and typically produce competing electric equipment.

The distribution operations area has RD&D needs in addition to the end-use area. RD&D funds for improved metering, materials of construction, safety, etc., come almost solely from the industry and GRI. Efficient and safe operations by the gas industry are almost taken for granted, but technological improvements are continually needed to assure that situation continues.

PARTICIPANTS

Of the several hundred local distribution companies (LDCs) in the United States, only a handful have RD&D departments/groups per se. Those that do have relatively limited budgets and typically support RD&D directed toward specific end-use markets within their operating territory. These few active companies often address the larger market potentials through industry associations as described in the next section of this report. In aggregate the LDCs provide about $45 million in RD&D funds with 80 percent directed toward end use with the remainder directed toward operational issues. Of the end use total, almost zero is directed toward basic research, a modest share in applied RD&D, and the major share related to demonstration activities. In the operational area, almost all the available funds are directed toward applied RD&D activities. Very little technology transfer or commercialization activities are provided for by LDCs in the operations area, which reflects their very conservative nature.

There are several industry associations that collect gas industry funding support via various mechanisms. The GRI is by far the largest such association in terms of funding, programs, and staff. In brief, the associations are as follows.

- ***Gas Research Institute***

  The GRI was established to plan and fund an industry-wide contract RD&D effort on behalf of the overall gas industry. Its program is developed with input from a broad cross-section of the gas industry's technical and marketing resources. Its funding is provided primarily through a surcharge on interstate gas sales and its program is reviewed and approved by the Federal Energy Regulatory Committee (FERC). The portion of GRI funding designated for basic, crosscutting, end-use, and operational research, represents about $100 million. The details of the GRI program are contained in their five year Research and Development Plan and Program issued annually.

- ***New York State Gas Association (NYGAS)***

  NYGAS is an association of LDCs located in New York state. One of its activities is the sponsorship of contract research with similar goals as the GRI, but directed at New York state gas technology issues. Funding is obtained through a formula based on gas sales and meters. NYGAS provides about $3 million for RD&D activities split about 70/30 end use to operational, with a minimal amount for supply research.

- ***American Gas Cooling Center (AGCC)***

  The AGCC is an industry-sponsored center set up to support commercialization of emerging gas cooling technologies. The AGCC is supported by gas company memberships and has the ability to support technical and market surveys. AGCC is located and operates from the

American Gas Association offices and has two full-time professional staffers.

- ***Natural Gas Vehicle Coalition (NGVC)***

  The NGVC is an industry-sponsored organization designed to expand the commercial availability and use of natural gas vehicles. The Coalition is comprised of interested gas companies and vehicle, engine, and equipment manufacturers. Although the Coalition charge allows it to participate in any fashion it deems necessary to accomplish its mission, it currently is providing primarily promotion, government relations, marketing, and standards support.

- ***Industrial Gas Technology Commercialization Center (IGTCC)***

  The IGTCC is an industry-sponsored organization organized to evaluate new industrial end-use technologies, target marketing, and communication programs to locate sites for demonstrating new technologies, and to arrange the actual demonstrations. The IGTCC is supported by gas company membership and, in addition, solicits funds for individual demonstration programs. The level of demonstration funding varies widely year to year, but on average it ranges from $500,000 to $1 million.

  Although funding is a major issue, the most difficult problem is finding cooperative demonstration site partners.

- ***International Energy Agency (IEA)***

  The IEA is an international organization set up to bolster cooperation among the 21 member countries to increase energy security through energy conservation, development of alternate energy sources and energy RD&D.

Almost one-third of the demand/end use RD&D funds, about $100 million, comes from the manufacturers of residential and commercial appliances, industrial furnaces, power generation equipment, and vehicles. This RD&D is almost exclusively applied technology developments or marketing efforts. Technology developments are typically incremental improvements of existing equipment lines. The benefit of manufacturer RD&D is the marketing and implementation capabilities of these companies. However, the resources for RD&D, funding and manpower, especially in the appliance and furnace areas, are limited, and in today's economic climate, on the decline. The power generation and vehicle markets are more robust, but overall, the incentives for developing natural gas equipment over alternate choices are limited.

The manufacturers of instrumentation and equipment for gas distribution system operations are typically driven by larger markets than provided by the gas industry. Development of new plastic piping materials is one exception, with manufacturer RD&D funding supporting a continuing line of new products.

The government supports RD&D funding for gas end-use technologies at both the federal and state levels. On the federal side, DOE support for end-use related technologies is about $80 million in 1992. The majority of these funds, about $60 million, were directed toward fuel cell development (both coal and gas-derived fuels). Further detail of the DOE RD&D for natural gas can be found in DOE's *Natural Gas Strategic Plan and Multi-Year Program Crosscut Plan FY 1993-1998*, April 1992.

Other government agencies and departments such as the Department of Defense, Department of Commerce, Environmental Protection Agency, etc., also provide minor RD&D funding for natural gas. This funding is project specific, however, and is not coordinated to any overall strategy.

Several states fund energy research, such as the Pennsylvania Energy Office and the New York State NYSERDA program. Also on the state level, several programs exist to enhance industrial development in that state. To the extent natural gas technologies may play a role in such industrial development, funds are directed to that specific industrial technology.

International companies and organizations contribute to the gas RD&D resource base, although their RD&D is obviously not directly tied to U.S. technologies or needs. Foreign gas companies such as Osaka Gas, Tokyo Gas, British Gas, Gas Unie (Holland), and Gaz de France have robust RD&D programs in aggregate equal to or greater than the collective U.S. programs. As natural gas is an energy source with world-wide appeal, successful technology developments will have world-wide markets.

Most of the foreign programs are sharing results through GRI associate membership.

Regulation plays an essential role in the RD&D funding resources in the United States. At the federal level, the role of the FERC in the GRI budget process has already been discussed. However, federal energy strategy and funding is a critical issue. Over the past 13 years the budget for the Fossil Energy Office of DOE has varied between about one-quarter billion to one and one-quarter billion dollars. The percentage of funds allocated to natural gas has been between two and six percent of that total. Coal and nuclear research have dominated the budget despite natural gas providing more than 20 percent of the energy consumed in the United States In addition, gas is a domestically abundant resource.

Many industries in the United States rely on the federal government and/or a pooling of research funds for much of their RD&D effort. Agriculture has been a major beneficiary of government-sponsored research and development, and has achieved major technology development. The medical industry has the National Institute of Health. The commercial aircraft industry has benefited from NASA (National Aeronautics and Space Administration) and the Defense Department. The electric utilities have much support from DOE.

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 applications. To achieve this, the technology must be transferred to the industry and its customers. The government can assist in this transfer of technology in many ways, including demonstrations, purchase for its own use, tax benefits, subsidization of early market activities; etc.

The role of the federal government in cooperative RD&D with the natural gas industry is recognized as critical in achieving the technology advancement necessary to expand its contribution to the national energy mix. In a report by Washington Policy Analysis (WPA), *U.S. Natural Gas: An Investment Strategy for Energy and Environment* (1992), it is pointed out that one of the specific actions in connection with natural gas that was called for in the 1991 National Energy Strategy (NES) is to "conduct government-industry cost shared RD&D of new technologies." The WPA report concludes benefits from such cooperative RD&D would provide clear and direct returns to the U.S. economy within three years with long-term environmental and energy security benefits as a bonus.

A second report, *U.S. Department of Energy, Ten Year Funding Recommendations by the Natural Gas Industry* (April 1991) recommends a $2.5 billion long-term (10 year) program emphasizing the key natural gas technologies needing government funds to augment the industry funding. This plan calls for an average of about $200 million per year in utilization technology support and about $50 million in supply technology support.

Cooperative research will help establish ties 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 or no industry participation and an assurance of better project selection.

On the state side, the current regulatory process requires local distribution companies to support expense levels, including RD&D before these expenses can be included in the rates charged to consumers. Many intervenors, especially those that represent electric utilities, residential consumers, small businesses, and large industrial customers, participate in the regulatory proceedings. These intervenors 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 RD&D programs that can readily demonstrate benefits to consumers.

Historically, state public utility commissions (PUCs) have accepted federally approved rate levels and have allowed LDCs to pass these costs on to their customers. In recent years the charge included in an LDC's gas cost from its gas supplier for the funding of the Gas Research Institute 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? The PUCs are likely to consider any additional recovery for RD&D programs funded directly by the LDC, in the context of the existing contribution to the GRI.

The focus group for state public utility commissioners indicated a belief that RD&D is very important to increasing demand. They support the view that the GRI has done a good job of new product development, but the commercialization effort needs strengthening.

The focus group for state PUC staffs indicated a general view that research, development, and commercialization is 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 also seen as impeding RD&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 provide little reward to shareholders for expenditures on research, development, and commercialization of new process and end-use technologies. A "cost plus" rate of return methodology provides little reward for vigilant economizing, rapid adoption of new technology, or creativity in meeting the needs of customers. There is little reward for constant efficiency gains or bold initiatives in offering new services. In this system, if investments lead to greater efficiencies (i.e., reduced costs) then allowable rates are simply lowered at the next proceeding so that the rate of return remains at the authorized level. Similarly, if an 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 discussions of the LDCs and the PUCs that there is a basic limitation in the market communication mechanism that is required for the operation of the fundamental premise for RD&D investment. That is, the benefits from RD&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 LDC are: Why should I (as a regulated LDC) make the investments in RD&D if:

1. I cannot realize any benefit from the investment.
2. My shareholders cannot realize any benefit from the investment.
3. I must spend time and effort in justifying the investment to the PUC for cost recovery.
4. My shareholders may incur additional investment risk without cost recovery.

CONCLUSIONS AND RECOMMENDATIONS

Conclusions

1. The current collective natural gas RD&D activities are inadequate.
2. Commercialization is the weakest element.
3. Many of the benefits of increased natural gas consumption do not necessarily translate directly to the bottom line of manufacturers and suppliers, thus minimizing their incentive and participation.
4. Neither the nation nor the gas customers benefit unless research and commercialization are successfully pursued.

Recommendations

1. Increase research and commercialization activities of all segments.
2. Federal and state governments are major users in some end-use market segments and thus should participate directly in those instances through purchase, use, etc.
3. Appropriate federal government incentives should be put in place such as tax incentives, subsidies, etc.
4. Commercialization organizations, such as the greatly expanding AGCC, NGVC, and IGTCC should be supported at a greater level of activity.

5. Regulatory agencies should take a proactive, positive stance.

6. 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.

7. Develop an innovative national funding mechanism for the demonstration and market introduction (i.e., early new product commercialization activities by equipment manufacturer) of successfully developed new gas equipment, with an annual gas industry funding level of $100 million to $200 million.

CHAPTER EIGHT

NPC NATURAL GAS STUDY MODEL RESULTS

INTRODUCTION

There are a large number of energy demand projections available from an assortment of sources: consultants, public and private companies, trade associations, and others. The available projections contain widely divergent opinions of what the mix of future energy demand will look like. In developing a projection, the Demand and Distribution Task Group did not want to simply increase the number of opinions available to decision makers. In fact, the National Petroleum Council determined that it was inappropriate to produce a base case or most likely reference scenario. Instead, the NPC decided to develop *two* reference scenarios—Reference Cases 1 and 2—which it felt bracketed the likely range of future gas and energy demand in the absence of the introduction of any major new public policy directions or significant new gas technologies that are not now available or expected to be available in the near term.

Reference Case 1

Reference Case 1 results from a Moderate Energy Growth Scenario, which assumes total energy grows at an average annual rate of 1 percent to reach roughly 100 quadrillion BTU (QBTU) by 2010. It includes moderate economic growth (GNP grows at 2.4 percent per year), energy efficiency improvement at a rate consistent with recent history (roughly 1 percent per year), and a growth in world oil prices to about $28.00 per barrel by 2010 (1990$). The demand side of Reference Case 1 includes an estimate of how current environmental laws will be implemented. It does not include the more extreme scenarios of environmental regulation, such as the implementation of a CO2 tax. This Case does, however, take a relatively more optimistic attitude toward the resolution of constraints to increased gas use. For example, constraints blocking the implementation of new technologies, extension of the existing transmission and distribution infrastructure to serve new customers, and elimination of regulations that impede growth in gas demand. Further, Case 1 assumes the continued availability of gas technologies to meet the requirements imposed by regulators and customers both today and in the future.

Reference Case 2

Reference Case 2 is based on a Low Energy Demand Scenario with total energy consumption growth limited to 0.5 percent per year, reaching roughly 88 QBTU by 2010. Growth is assumed to be constrained by slow growth in economic activity (GNP grows at only 2.0 percent per year) and more rapid improvement in energy efficiency, particularly in the industrial sector. It is assumed that the more modest growth in energy demand places less pressure on energy supplies and, as a result, energy prices are lower in this Case. World oil prices are assumed to reach only $20.00 per barrel by 2010 (1990$). This provides some stimulation to energy demand, but not enough to offset the effects of lower economic growth and more rapid energy efficiency improvement.

As with Case 1, Reference Case 2 includes an estimate of how current environmental laws will be implemented. It does not include the more extreme scenarios of environmental regulation.

The development of two Reference Cases, which cover a range of energy demands in the future, provides a number of benefits to this study. First, it establishes a potential range of gas and energy demand without new specific concerted actions by the gas industry, federal, state, and local governments, or other parties. This provides a point of departure for evaluating the impact of efforts to improve gas competitiveness in markets or to evaluate the impact of policy changes. Finally, the use of a modeling framework provides a tool that, when used with a consistent set of assumptions, accounts for many of the specific interactions that take place in energy markets.

BRIEF DESCRIPTION OF MODELING APPROACH

The core modeling structure used in this study was the Energy and Environmental Analysis, Incorporated (EEA) Energy Overview Model. The Energy Overview Model includes three modeling structures: the Hydrocarbon Supply Model, the End-Use Sector Model, and the EEA Pipeline Model. The efforts of the Demand and Distribution Task Group were focused on the End-Use Sector Model. The Hydrocarbon Supply Model was used by the Source and Supply Task Group and is described in Volume II. The EEA Pipeline Model is described in Volume IV, the Transmission and Storage Task Group report.

The EEA End-Use Sector Model covers natural gas and other energy demands in the lower-48 states, focusing on the segments of energy markets in which natural gas competes directly with other fuels. The model's fuel coverage includes all purchased energy sources in the residential and commercial sectors (excluding wood and other renewables). In the industrial sector, all natural gas consumption is covered as are residual fuel oil, distillate fuel oil, coal, and electricity as competing combustor fuels. Oil and coal feedstocks (raw materials) and selected petroleum fuels (liquefied petroleum gases, kerosene, gasoline, still gas, petroleum coke, and crude product) are excluded. All energy inputs to electric utilities are covered. Except for natural gas vehicles, transportation sector energy demand is outside the scope of the EEA model.

To provide complete U.S. energy coverage and projections of economic activity in the United States, the Task Group also used the Data Resources, Incorporated (DRI) Macroeconomic and Energy Models. The DRI models were solved with assumptions for the NPC Reference Cases consistent with those used in the EEA Energy Overview Model. The DRI macroeconomic projections were then input to the EEA model to provide the main economic drivers of projected energy demand. DRI projections of transportation energy demand and the components of industrial sector energy not covered in the EEA model were used to provide a complete energy coverage for the NPC Reference Cases. Volume VI of this study contains further documentation of the DRI and EEA models along with input assumptions and model output.

Figure 8-1 presents an illustration of the EEA End-Use Sector Model. The following discussion provides a summary overview of the characteristics of each of the main components of the model.

Residential/Commercial Sector

The EEA residential/commercial sector model uses an econometric approach that projects energy demand as a function of fuel prices, disposable income, and building stock growth. The model distinguishes between new and existing buildings. It tracks the inventory of energy equipment in the existing stock, accounts for depreciation and retirements over time, and adds new energy using equipment to meet replacement needs and growth. The model explicitly distinguishes between short and long-term decisions using different elasticities for each decision. The EEA residential/commercial sector model framework is shown in Figure 8-2.

Industrial Sector

The EEA industrial sector model is a simplified process engineering model that considers energy consumption in industrial combustors for the nine major industry groups and for fifty specific functional uses. As already noted, it does not model industrial oil and coal feedstock energy use and selected petroleum fuels, which were modeled with the DRI run. The EEA model explicitly considers the economics of natural gas versus alternative energy

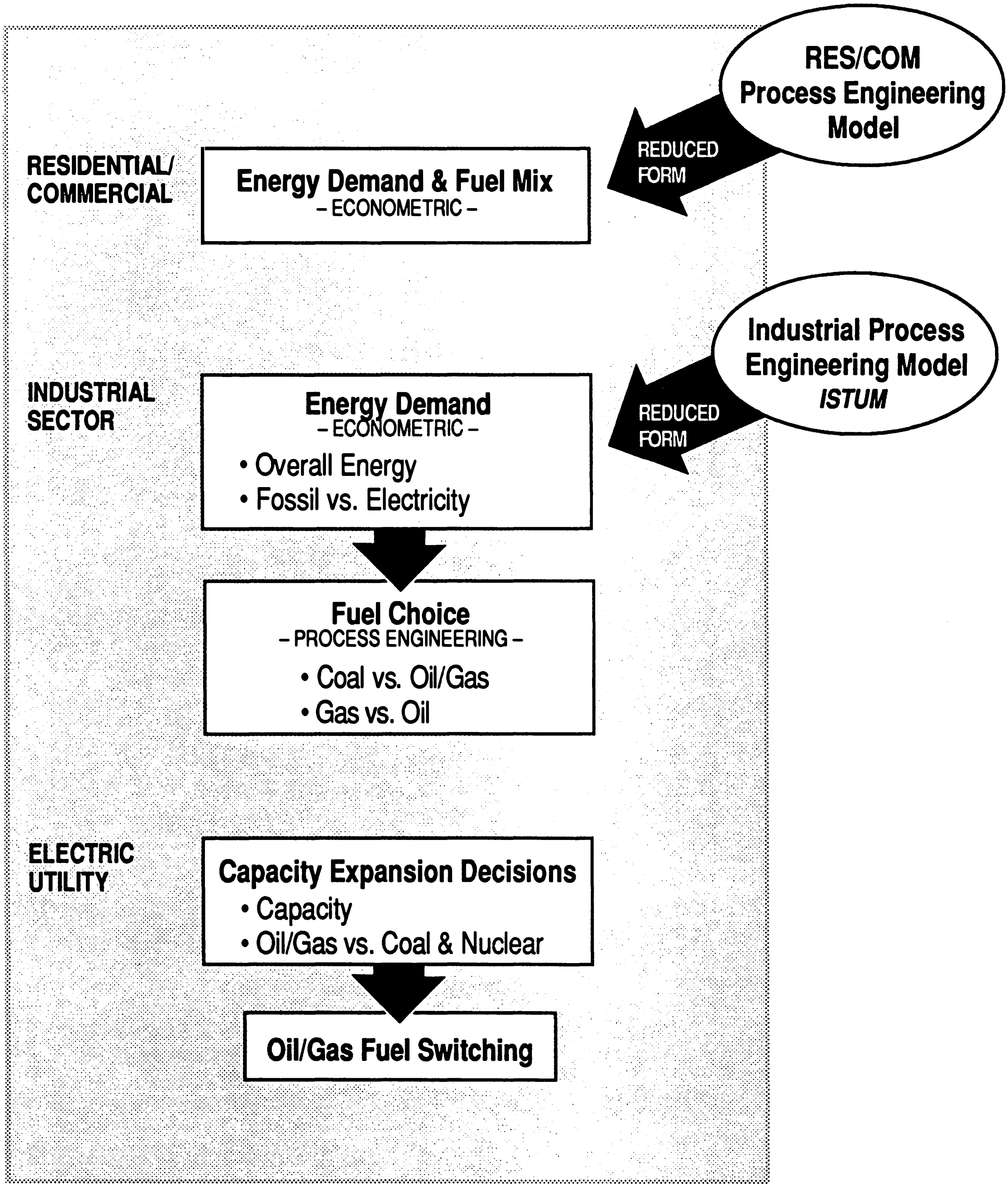

Figure 8-1. End-Use Sectoral Demand Models.

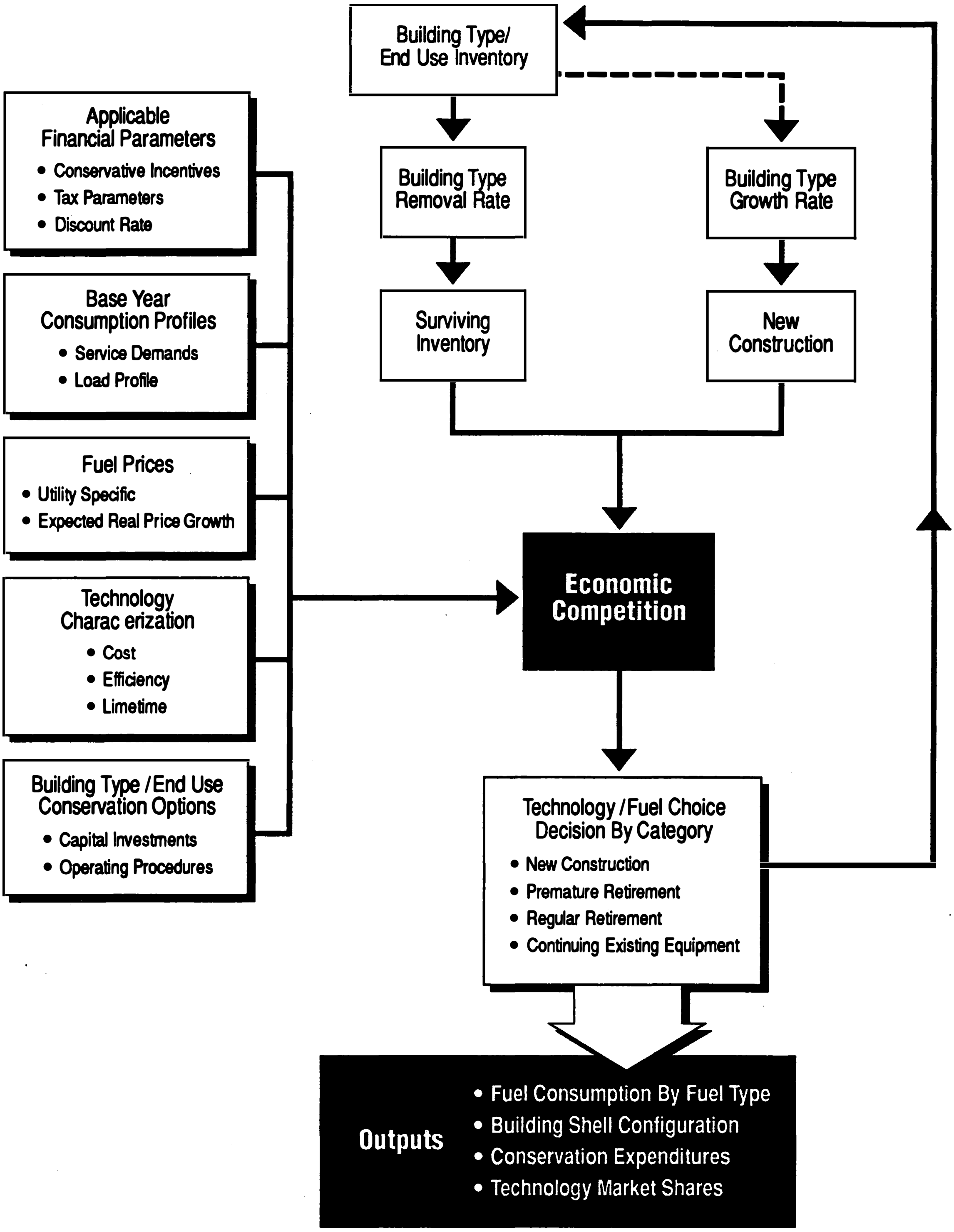

Figure 8-2. Framework for Residential/Commercial Demand Analysis.

sources and reflects the technical constraints of energy use by fuel type. The major factors affecting cost include combustor size, capacity utilization, current fuel-firing capability, regional location, and whether it is a new or existing combustor. The model explicitly reflects existing environmental requirements and control costs. The decisions in the model are based on life cycle cost minimization. The model also calculates the *potential* for fuel switching based on the characterization of the capital stock (i.e., installed single or dual-fired, technical feasibility of fuel substitution, and alternative fuel type). The economic calculation of fuel switching depends on fuel prices, operating and maintenance (O&M) cost differences among fuels, the levelized cost-of-equipment retrofits in single-fired units, and environmental restrictions on sulfur dioxide emissions. The EEA industrial sector model framework is shown in Figure 8-3.

Electric Power Sector

The EEA electric power sector model accounts for 23 power plant types, three load categories (i.e., base, intermediate, and peak), and all fuel types that used power generation. The model:

- Tracks capital stock changes in the regional power plant inventory
- Projects long-term fuel choices in new units
- Makes short-term oil/gas fuel choice decisions
- Projects regional electricity production costs and fuel consumption
- Projects regional electricity prices by sector.

The EEA electric power sector model framework is shown in Figure 8-4.

Capital stock changes are tracked in the EEA model through regional inventories of existing plants by load class, type, and age. Plants are retired based on assumptions concerning the operational life of units, fuel, and capacity type, and may be refurbished and/or repowered over time according to the user's scenario. The demotion over time of older fossil fuel steam units from base to intermediate load service is also simulated.

Capacity planning decisions are made using a combination of announced construction plans of the electric utility industry and an economic competition between unit types to determine the longer-term fuel mix in new units. At present, industry announcements cover units planned to be on-line to approximately the 1998-2000 period. Although the types and amounts of new capacity in this period are based on industry plans, the actual on-line dates may be delayed in model forecasts if not required to meet projected electricity demand growth. Beyond the period of announced plans, an endogenous economic competition is conducted between natural gas-fired and coal-fired units for new base load generation requirements. This competition considers capital costs by unit size (small versus large), non-fuel O&M, and fuel costs over an expected 30-year operating life of the new unit. The projected mix of new units is determined through an economic market share function and consideration of institutional and lead-time constraints on the fuel choice.

A merit order dispatching algorithm is used to determine the average annual capacity utilization rates for each plant type. After nuclear and hydroelectric plants have been dispatched, coal, oil/gas combined-cycle, and oil/gas steam units are then dispatched within each load class. Unit heat rates are distinguished by unit type, load class, and new versus existing units, and may be adjusted for refurbishment and future technological advances.

Fuel selection in dual-fuel capable units is modeled on a least cost basis, subject to constraints of existing environmental regulations, and the impact of SO2 allowance provisions under the Clean Air Act Amendments of 1990. All utility boilers are assumed to be capable of firing residual fuel oil and are switched based on fuel prices, a cost premium for conversion if single-fired, and market share functions representing the distributions of fuel availability and costs within a region. All peaking turbines and combined-cycle units are treated as capable of firing distillate fuel oil and are switched based on economics.

Regional fuel consumption and electricity production costs are determined from plant utilization and heat rates, fuel selection, and fuel costs. The model also tracks capital accounts for private and publicly owned utilities and projects

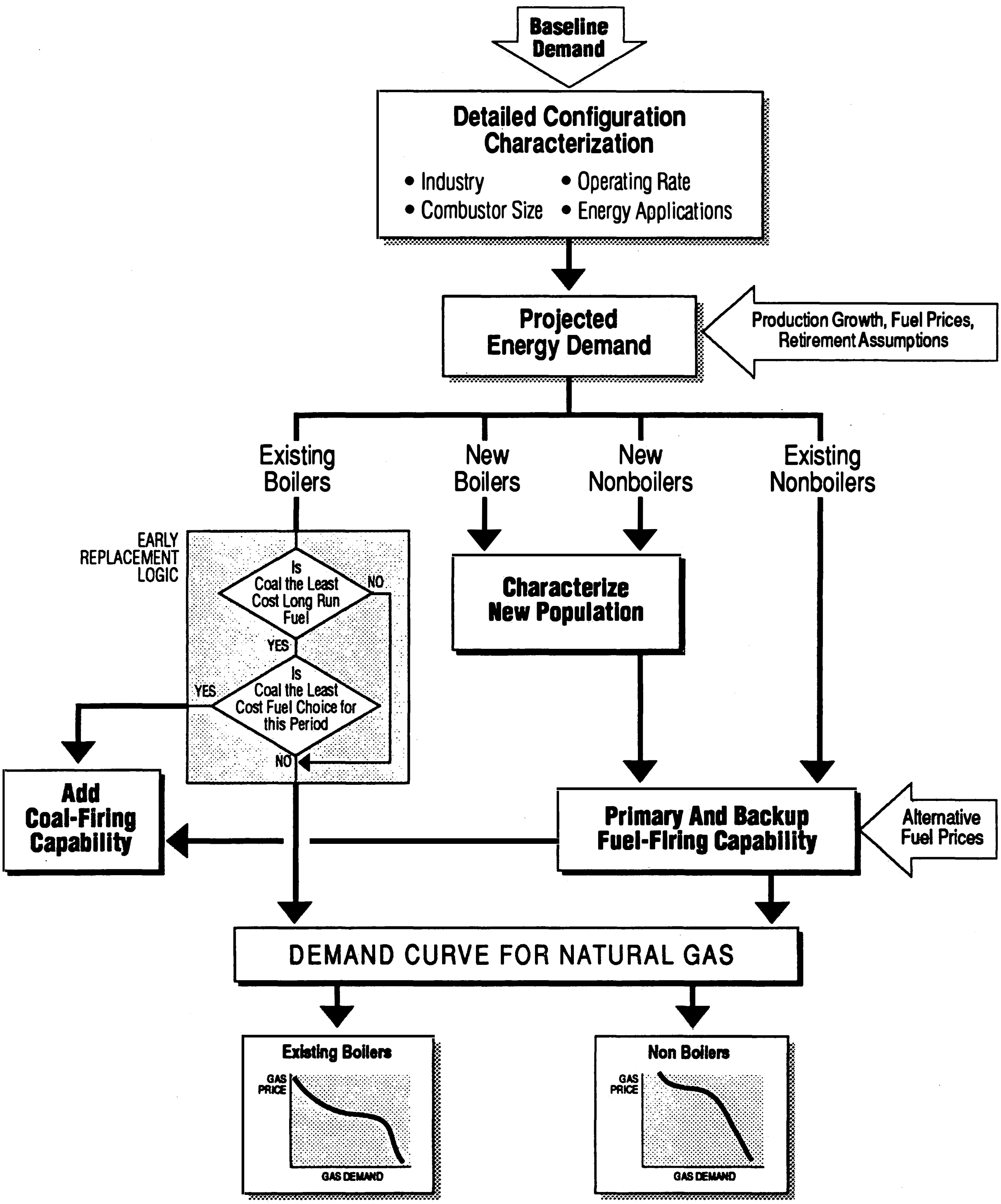

Figure 8-3. Industrial Gas Demand Model Framework.

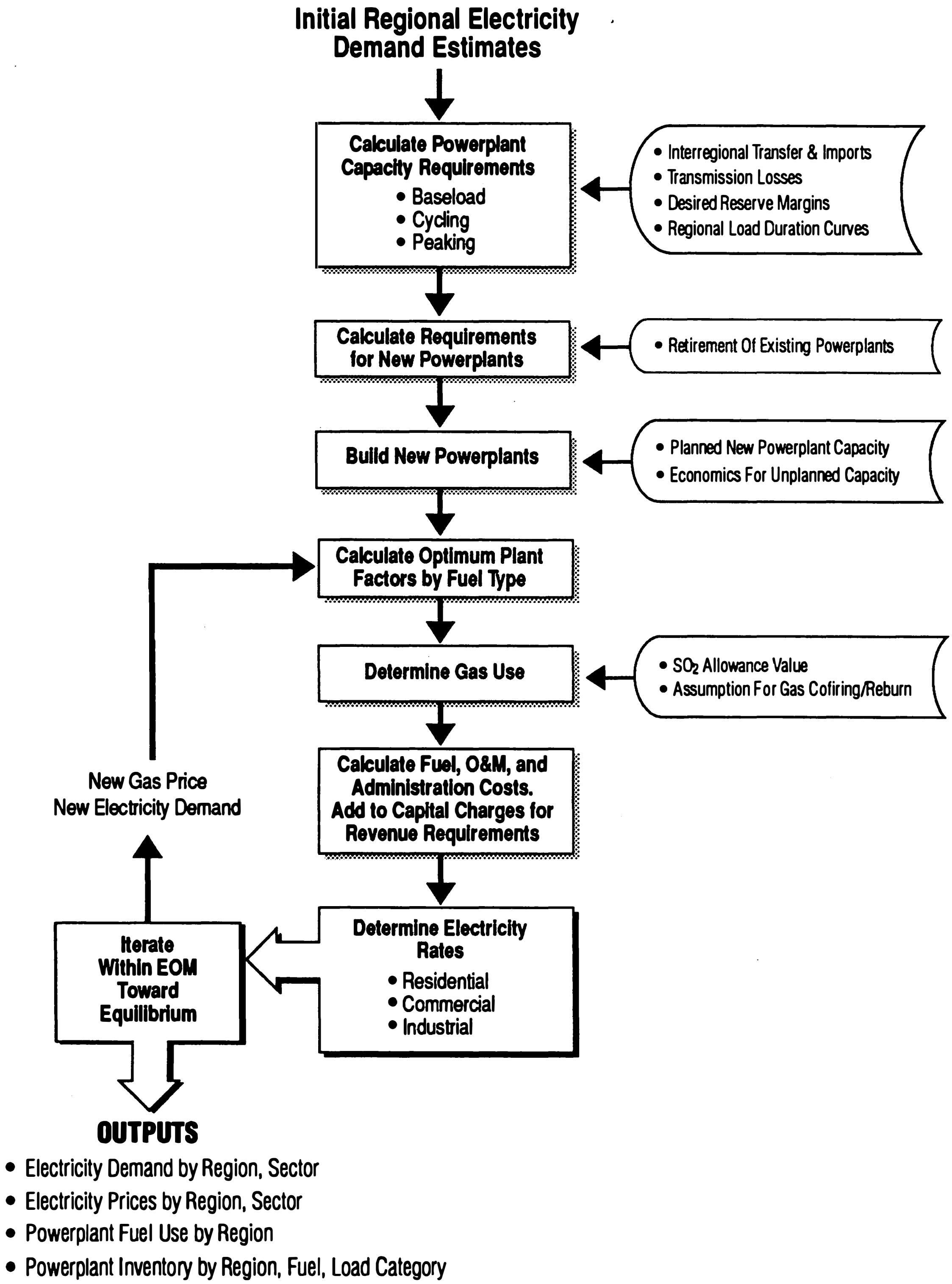

Figure 8-4. Electric Utility Model Framework.

electricity rates through revenue requirement calculations. The rate base is compiled from FERC/DOE data for existing units, and additions to the rate base track in separate, vintage accounts for new units. The price of electricity is determined from three components: a capital charge (based on depreciation, taxes, and return on total rate base), fuel costs, and O&M and administrative costs. Revenue requirements are then allocated to the end-use sectors (residential, commercial, and industrial) based on historical allotment practices to determine electricity prices by sector.

GENERAL ASSUMPTIONS

Philosophy

While the publications summarizing many projections explicitly discuss their assumptions about the more physical factors—energy prices, economic growth, and regulations—few discuss the assumptions made implicitly about the more philosophical factors—the future direction of historical trends, the extension of existing regulatory paths, or the decision maker's "expectation" about the track of future energy prices. However, these implicit assumptions, often resulting from the forecasters' own biases, are as important to the projection results as any of the more concrete assumptions being made.

During production of the demand projections for this study, a number of these normally implicit assumptions were made explicit. They were discussed and general philosophies were developed about how they should be incorporated in the projection. Following is a discussion of the philosophies developed about these assumptions.

Direction of Trends

Since the 1960s, the underlying trend in a number of variables significant to energy markets have changed dramatically. This includes both the general direction and relative strength of these trends. These changes have generally come about in response to some external stimuli. For example, new public policies, political shifts (the increased influence of OPEC), or social changes. Many of these stimuli are difficult, if not impossible, to predict.

The Demand and Distribution Task Group had to develop attitudes about a number of specific trends that underlie the projection. Specifically, the rate of decline in energy intensity, the change in the mix of industrial production by SIC (Standard Industrial Classification), attitudes on the part of both the general public and electric generators about the desirability of new coal-fired power plants, and the rate of improvement in gas-fired technologies. In each Case, the Task Group did not try to anticipate radical shifts in trends due to external stimuli but instead assumed that the trends would follow some variant of the recent historical path. Table 8-1 summarizes the basic philosophy adopted about each of the trends addressed.

Energy Intensity

The rate of improvement in residential and commercial energy intensity slowed in the 1980s relative to what occurred in the 1970s. The Task Group decided that this trend was likely to continue. Between 1980 and 1988, residential energy intensity declined at a rate of roughly one percent per year. Over the same period, commercial energy intensity declined at a rate of about 0.6 percent per year. Energy intensity, as shown here, is measured using weather normalized data. For the projections (both NPC Reference Cases), the Task Group targeted energy intensity improvement at roughly one-half of the 1980 to 1988 historical rate.

The rate of improvement in industrial energy intensity also slowed in the 1980s relative to what occurred in the 1970s. However, the slowdown in the rate of improvement was not as great as that experienced in the residential and commercial sectors. Between 1983 and 1990 industrial energy intensity improved at a rate of 1.6 percent per year. The Task Group felt that a more conservative assumption about the slowdown in the rate of improvement in energy intensity in the industrial sector was appropriate. For Reference Case 1, the targeted rate of energy intensity improvement was consistent with the rate experienced between 1983 and 1990. However, in Reference Case 2, the targeted rate of energy intensity improvement was set consistent with the faster rate experienced historically between 1973 and 1980. During that period, industrial energy intensity improvement occurred at a rate of 2.5 percent per year.

TABLE 8-1

ASSUMED DIRECTION OF TRENDS

	Reference Case 1	Reference Case 2
Energy Intensity		
Residential & Commercial	Continued Decline from Rate of 1980s	Continued Decline from Rate of 1980s
Industrial	Consistent with 83-90 Trend	Consistent with 73-80 Trend
Change in SIC Mix	Consistent with 83-90 Trend	Consistent with 83-90 Trend
Institutional Constraint on New Coal-Fired Capacity	Additional New Coal-Fired Capacity Constrained to Published Utility Plans Through 2000, Full Economic Calculation Beginning in 2004	Additional New Coal-Fired Capacity Constrained to Published Utility Plans Through 2000, Full Economic Calculation Beginning in 2004
Gas Technology	No Significant Inroads in New Gas End-Use Technologies, With the Exception of Some Cooling Technologies	No Significant Inroads in New Gas End-Use Technologies

Change In SIC Mix

A major contributor to the change in the level and mix of industrial energy consumption since 1970 has been shifts in the underlying mix of industry by SIC category. However, the two-digit SIC measure of production commonly used by forecasters provides inadequate information about how energy is used in each industry. For example, in the Primary Metals industry (SIC 33) the energy input in a steel mini-mill is very different than the energy used in a full-scale primary steel producing facility. However, the dollar value of the output could be identical. Between 1973 and 1980, total industrial fuel and power energy consumption declined by 1.4 QBTU. EEA estimates that shifts in the SIC mix account for 0.8 QBTU of this decline.

Many publicly available projections do not reflect these underlying changes in the SIC mix and the impact on energy consumption. Fixed relationships between production, measured by two-digit SIC categories, and energy consumption are used. There was no reason to assume that this SIC mix change would cease through the 1990s and beyond. However, the Task Group did not have any information about how the mix change might evolve. They therefore decided that it was appropriate to assume that the SIC mix change experienced in the 1980s would extend into the 1990s in both Reference Cases. This assumption has the impact of slightly lowering industrial energy demand growth relative to what it otherwise would be.

Institutional Constraint

The ability to add new electric generating capacity is constrained by construction lead-time, which varies by capacity and fuel type. For example, a gas-fired turbine designed to meet peak load can generally be constructed in 2 or 3 years while a large coal-fired unit designed for base load can take as long as 8 years to build. Among a large number of factors, the actual construction lead-time will vary depending on local regulations, on whether the unit to be built is a green field facility or is being built at an existing generating location, and depending on the availability of the fuel source. Reflecting this lead-time constraint, many projections include only the announced central utility and non-utility (NUGs) published plans for new capacity through the 1990s. Model determined new capacity is generally not added until after the year 2000. The near-term generating capacity outlook is essentially predetermined.

Compounding this issue is an institutional constraint that is effectively limiting the central utilities' ability to choose and build new base load coal-fired generating units.

New generating capacity decisions were not being made based on the comparative economics of the potential capacity alone. In addition to the completion of coal and nuclear units ordered many years ago, the only new generating units being constructed today are gas-fired turbines for peaking service (the majority of announced plans and construction) and a growing number of gas-fired combined-cycle units for intermediate and base load service. Given the lead-time for coal unit construction, the longer central utilities wait to announce new coal-fired plants, the less impact the facilities will have on pre-2010 energy consumption for electricity generation.

The apparent reluctance to announce and start construction of new base load coal-fired generating capacity stems from many factors: the disallowance of nuclear plant construction costs during the 1970s and 1980s, the perception of coal as environmentally unsound, and a public aversion to the construction of any new energy using facility (the "not in my backyard" problem). The Task Group recognized this constraint and discussed when it might begin to ease and what were the implications for the introduction of new coal-fired generating capacity. The conclusion was that the perceived reluctance to build new coal-fired facilities would not begin to ease until the late-1990s. As a result, the Task Group incorporated constraints in the model limiting new coal-fired generating capacity additions beyond those already planned. Gas share floors were established limiting coal penetration in the near term. The model's determination of new capacity was not based strictly on economics until 2004. Start-up of a plant in 2004 implies that a utility announces the plant and begins the process leading to construction between 1996 and 1999. This limitation was applied in both Reference Cases.

Gas Technology

The competitiveness of gas in end-use applications depends on many factors besides relative price. One important additional determinant of the competitiveness of gas is the relative state of gas technology. Improvements in electric- and petroleum-using technologies will continue in the future. For gas technology to remain competitive it must keep up with these improvements. However, from a modeling perspective, the introduction of new revolutionary gas technologies without including offsetting new electric and petroleum technologies would bias the outcome of the model results significantly toward gas. In Reference Case 1, the Task Group decided not to introduce significant new gas technologies that were not already available in the market. However, gas cooling equipment that is not yet in the market but is close to commercialization was introduced in this Case. A more conservative technology assumption was followed in Reference Case 2, in which no gas cooling equipment not already in the market was introduced. From a technology perspective, these assumptions make the model results, in both Cases, relatively conservative.

Extension of Regulatory Paths

There is a discernible trend in federal, state, and local public policy to place more emphasis on protecting the environment. In some cases, particularly concerning the Clean Air Act Amendments of 1990, the specification of enacting legislation is not yet complete and the full implication of the Amendments for energy markets is still uncertain. It is very easy to propose new directions for environmental legislation given the current trends. For example, one could easily argue about the likelihood of a CO_2 or BTU tax in the near future. However, given the potential bias in energy decisions of selecting one approach for new environmental legislation over another, the Task Group decided to simply include an interpretation of current laws and not try to anticipate new environmental laws.

The Task Group also took the approach of not trying to guess the direction of other potential regulatory changes. This included efficiency regulation (beyond that specified in the National Appliance Energy Conservation Act), state and local regulations involving construction and permitting, and new non-energy taxes. Implicitly, the Task Group assumed a workably competitive environment in which the driving force of the markets was economics, with the exceptions previously discussed.

Gas Price Expectations

An often neglected philosophical aspect of modeling is the determination of how an energy decision maker views future energy prices. Energy prices, at least since the 1970s, have not followed a steady, predictable path. The real world decision maker's perspective on what he believes the path of future energy prices will look like is based on a combination of factors: recent experience, personal biases, current analytical thinking, etc. Many projections are based on an assumption of perfect foresight. With this approach, the energy decision made today is based on an assumption that the decision maker knows, with certainty, the future price track. As recent experience and investment mistakes suggest, few decision makers have perfect foresight.

The Task Group addressed the issue of the gas price expectation logic and determined that it was inappropriate to assume perfect foresight. However, choosing an alternative was more difficult. There are an unlimited number of alternatives to assuming perfect foresight. Further, different price expectation logics produce very different gas market share solutions, especially if the gas price trajectories exhibit cyclical trends or reflect changing growth rates over time.

The price expectation logic that was eventually adopted for both Reference Cases assumes that gas users believe that delivered natural gas prices will reach residual fuel oil prices with some lag period (5 years) and then follow residual fuel oil prices over time. In other words, the energy decisions made today assume that future gas prices will move toward residual fuel oil prices and then track the path of residual fuel oil prices in the future. The price of gas projected by the model could be quite different than the price used in energy decisions under this price expectation logic. The price could be higher or lower and the decisions made may not be entirely consistent with the projected price path.

Economic, Demographic, and General Assumptions

Table 8-2 highlights the more general economic and energy assumptions made for the two Reference Cases. Reference Case 1 was intended to reflect a world of moderate, not strong, economic growth. The basic assumptions were set consistent with this approach. The economic variables were developed largely based on recent historical experience. However, the rate of growth in some variables was set below historical experience in situations where there has been a distinct decline in the rate of growth in recent years.

The major adjustment made in Reference Case 2 was an assumption of slower economic activity, which was reflected in the adoption of a lower rate of growth in GNP.

TABLE 8-2

KEY ECONOMIC AND ENERGY ASSUMPTIONS
(Percent Change Per Year: 1990 to 2010)

	Reference Case 1	Reference Case 2
Economic		
Gross National Product	2.40	2.00
Disposable Income	1.80	1.49
Industrial Production	2.70	2.25
Population	0.64	0.31
Residential Housing	1.01	0.74
Commercial Floor Space	1.40	1.08
Energy		
U.S. Energy Demand (Targeted)	Approx. 100 QBTU	Approx. 88 QBTU
Energy Taxes (New)	None	None

The other economic variables were generally adjusted roughly proportional to the ratio of GNP growth in the Reference Cases.

Given expectations for GNP growth and improvement in energy intensity, a general target for U.S. energy demand was specified for both Reference Cases. This was a way to characterize the desired range of energy demand between the two Reference Cases. It is important to emphasize that these are target demand levels. The final projection results are consistent with, but are not necessarily identical to, these targets.

ENERGY PRICES

This section discusses the derivation of the crude oil, natural gas, and coal acquisition prices. The delivered prices are discussed in the sections of the report that deal with the end-use sectors.

Crude Oil

Table 8-3 presents the refiners' acquisition cost of crude oil price path in 1990 dollars per barrel used in the Reference Cases.

A great deal of uncertainty exists concerning future oil prices. Since 1970, there have been three major oil supply disruptions that led to price spikes; prices have declined sharply in response to decisions implemented by major oil producing countries; and quota cheating by OPEC members have contributed to continued softness in oil prices. Against this backdrop, world dependence on OPEC declined sharply after 1973 and grew steadily since 1985. The OPEC share of total world oil production grew from 30 percent in 1985 to almost 39 percent by 1991 (still significantly less than the 54 percent share achieved in 1973). Complicating the situation is the major economic powers' renewed determination to protect their interests as evidenced by the response to Saddam Hussein's invasion of Kuwait.

TABLE 8-3

REFINERS' ACQUISITION COST OF CRUDE OIL (1990$ per Barrel)

Year	Reference Case 1	Reference Case 2
1990	22.32	22.32
1995	19.01	15.50
2000	21.10	17.00
2005	25.14	18.50
2010	27.85	20.00

To avoid a potential protracted debate about future oil prices, the refiners' acquisition cost of crude oil price used in Reference Case 1 was specified by the NPC at the beginning of the study. They reasoned that world oil demand has resumed its upward trend following the collapse in price in the mid-1980s. This increase in demand has been accompanied by an increased call for oil from the OPEC nations. Under the conditions of moderate economic growth assumed in Reference Case 1, it is expected that total world oil demand to increase by as much as 50 percent over the next 20 years. These circumstances suggested it was reasonable to expect some real oil price growth. The NPC felt that the scenario described was consistent with real price growth of roughly one percent per year. Based on this logic, a price of about $28.00 per barrel was selected for 2010.

Reference Case 2 assumes that economic growth in the United States and other industrialized countries is slower than that in Reference Case 1. Consequently, world oil demand growth would also be slower. Given reasonably abundant world oil supplies, it followed that slower growth in demand would result in a lower oil price.

The NPC noted that the wide range of the price paths chosen for the Reference Cases was consistent with published projections available at the time (May 1991). These projections ranged from a high of about $36 in 2010 to no real growth through 2010 (roughly $20 per barrel). The Council further stressed that neither price track should be considered a most likely case. The intent was to establish a range of prices wide enough to represent significantly different alternative futures while remaining reasonably consistent with the publicly available projections.

Natural Gas

Natural gas prices were an output of the model. However, the projections of gas price involved making numerous assumptions; for example, about trends in drilling costs, resource appreciation, technology change, and the size of the resource. A complete discussion of the natural gas price projections is included in Volume II, Source and Supply.

Table 8-4 shows annual average lower-48 wellhead gas prices for the United States in 1990 dollars per million BTU (MMBTU). The Task Group recognizes the importance of regional and seasonal differences in gas prices and these differences are explicitly considered in the model. Further, the impact of these differences on the relative economics of various energy decisions is also considered in the analyses.

It is important to highlight a series of implicit assumptions made in the model concerning natural gas supply and price that imply a degree of uncertainty with the prices shown in Table 8-4. First, the model assumes that the investment necessary to develop the gas resource will continue to occur in the future. The model does not calculate the tradeoff between investing in the U.S. and overseas. Further, the model assumes that the necessary capital will be available for investment needs. The model does not evaluate the relative merits of capital investments in the many opportunities in the U.S. economy. Last, the model assumes that technological progress in gas supply development and production will continue to occur at rates near historical trends. This implies both the continued funding and development of improved gas supply technologies and their implementation in the field. If any of these implicit assumptions are not met, the prices used in the analysis could be significantly different from those shown in Table 8-4.

Coal

The average delivered price of coal in both nominal and real dollars has been dropping steadily since the mid 1980s. In 1984, the nominal price of coal delivered to electric utilities was $1.66 per MMBTU. The nominal price dropped to about $1.45 per MMBTU by 1991. This represents an annual compound decrease of almost 2 percent. In real 1990 dollars, this corresponds to a drop from $2.06 in 1984 to $1.40 per MMBTU or by 5.7 percent per year.

TABLE 8-4

AVERAGE LOWER-48 WELLHEAD NATURAL GAS PRICE (1990$/MMBTU)

Year	Reference Case 1	Reference Case 2
1990	1.66	1.66
1995	2.04	1.68
2000	2.94	2.42
2005	2.79	2.51
2010	3.43	2.78

The reasons for this decline have been the continued existence of surplus coal supplies, rapid improvements in coal mine productivity, and relatively flat transportation charges. The decline in the average price is driven by the "rollover" or re-negotiation of old, long-term contracts and increased spot purchases of coal by electric utilities. In fact, one of the difficulties in using coal prices in the model is that the relative economics of coal versus other fuels in *new* decisions is not based on the weighted average U.S. price of coal but on the new contract price of coal which is significantly lower than the average.

For the analysis, the Task Group used coal prices developed by Hill & Associates. Table 8-5 presents the U.S. weighted average low and high sulfur coal prices in 1990 dollars per MMBTU delivered to the electric power sector. The coal price input from Hill & Associates was based on delivered coal prices and not mine-mouth or acquisition prices. However, delivered coal prices to the electric power sector closely approximate the mine-mouth price since transportation costs are relatively low per ton of delivered coal to electric generators in most parts of the United States.

Hill & Associates developed the coal price tracks based on the following basic assumptions:

- For almost all coal types in all regions, the base recoverable reserve is large and the supply curve is flat. New mines will not cost much more than existing operations in most regions. In fact, some new mines will cost less than existing operations.

TABLE 8-5

AVERAGE DELIVERED COAL PRICE TO ELECTRIC GENERATORS (1990$/MMBTU)

	Reference Case 1		Reference Case 2	
	Low Sulfur	High Sulfur	Low Sulfur	High Sulfur
1990	1.52	1.40	1.52	1.40
1995	1.61	1.35	1.55	1.32
2000	1.69	1.30	1.56	1.24
2005	1.71	1.27	1.58	1.21
2010	1.74	1.27	1.61	1.21

- Productivity has risen rapidly in the coal industry over the past ten years. Although it is likely that the rapid increase of recent years will slow somewhat, annual productivity improvement should be great enough to offset inflation and any deterioration in mining conditions as more expensive reserves are mined.
- Transportation costs will remain flat in real dollar terms over the course of the next 20 years. During the period since 1984, transportation rates (as reported by the ICC) have fallen slightly in real terms. This decline has come from (a) the increased competition fostered by the Staggers Act, (b) a decline in oil prices, and (c) significant reductions in railroad labor costs.

Hill & Associates noted that some of the downward pressure on coal prices will be offset by the increased displacement of high sulfur coals with low sulfur coals to comply with Phase 1 of the Clean Air Act Amendments of 1990, particularly between 1995 and 2000. With the increased demand for low sulfur coal, Hill & Associates projected that low sulfur coal prices would increase over the projection period. While not shown in the table, the average price of coal is projected to increase in regions that are expected to experience the most switching to low sulfur coals.

While Table 8-5 shows the average coal prices assumed for the analysis, as already pointed out, the economics of a new decision on whether to use coal or an alternative fuel is based on coal prices that are lower than the average price. This distinction was accounted for in the model in both Reference Cases. The economics of the continued operation of existing coal-fired plants were based on the weighted average U.S. coal price, but the decision to build a new coal-fired power plant was based on the new contract price of coal. The new contract price of coal was, on average, about 16 percent lower than the average U.S. coal price in 1991. The analysis assumes that this 16 percent difference remains constant over the projection period. This distinction will be discussed more in the section of the report on the electric power sector.

The uncertainty associated with coal prices is generally not a result of potential resource problems or international political upheavals. The uncertainty stems largely from potential regulation: the possible enactment of a CO2 tax (which would impact coal more than gas or oil), outright restrictions on coal consumption, or limitations on the allowable content of sulfur in coal. The projection did not consider such extreme changes in regulatory policy. However, the projection did include the impact of existing regulations on coal prices and consumption.

SUMMARY OF TOTAL ENERGY CONSUMPTION

The discussion of the scenario results is based on the output from the EEA model. As noted earlier, the model does not provide complete coverage of every aspect of energy markets. For example, the projection coverage is limited to only the lower-48 states. Further, the model does not provide a projection of transportation energy consumption with the exception of natural gas vehicle (which is included in the commercial sector) and pipeline transmission consumption of natural gas. The model does not provide a projection of coking coal or petroleum feedstock use in the industrial sector. The model also excludes certain types of industrial fuel and power energy consumption. In total, these exclusions are important, accounting for 28.7 QBTU of total U.S. primary energy consumption in 1990. However, despite these exclusions, the model provides relatively complete coverage of natural gas consumption and the markets for which gas competes.

Primary Energy Consumption

Table 8-6 provides a summary of projected total primary energy consumption in the Reference Cases. Total primary energy consumption in Reference Case 1 is projected to increase at about 1.1 percent per year between 1990 and 2010. This is significantly less than the projected 2.4 percent per year growth in GNP over the long term. The projection of energy consumption includes a steady improvement in energy efficiency over time. In Reference Case 2, total primary energy consumption is projected to grow at a slower 0.5 percent per year over the same period. This is consistent with the slower 2.0 percent per year growth in GNP and the assumption of more rapid efficiency improvement, particularly in the industrial sector.

Natural Gas

In Reference Case 1, primary natural gas consumption is projected to increase at 1.4 percent per year over the projection period, or about 30 percent faster than the rate of growth in total primary energy consumption. As will be discussed later in the report in some detail, most of the growth is spurred by increased gas consumption for electricity generation both in the industrial (cogeneration) and electric power sectors (central utilities and independent power producers).

In Reference Case 2, projected growth in natural gas consumption is actually slower than growth in overall primary energy. Gas consumption is projected to grow at less than 0.5 percent per year between 1990 and 2010. Gas consumption growth is modified by three factors: strong price competition due to the assumption of flat oil prices; slow economic growth holding down energy demand growth in all sectors; and the assumption of stronger efficiency improvement (relative to Reference Case 1), which significantly reduces gas consumption in the industrial sector.

TABLE 8-6

TOTAL PRIMARY ENERGY CONSUMPTION IN THE LOWER-48 STATES
REFERENCE CASES 1 AND 2
(Quadrillion BTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Natural Gas*	18.8	21.4	19.1	24.8	20.6
Petroleum†	5.0	5.2	5.5	4.9	4.5
Coal‡	17.9	19.3	18.5	23.2	21.0
Nuclear/Hydro/Other	9.2	10.4	10.3	10.2	10.1
Total	**51.0**	**56.3**	**53.4**	**63.1**	**56.2**

* Includes lease and plant uses and gas pipeline fuel use.

† Excludes petroleum consumed in the transportation sector and as feedstocks in the industrial sector. It also excludes liquefied petroleum gases, kerosene, gasoline, still gas, petroleum coke, and crude product consumed for industrial fuel and power. In 1990 transportation petroleum consumption was 21.8 QBTU, industrial petroleum feedstock use is estimated to have been about 4.4 QBTU, and the excluded petroleum fuel and power categories accounted for 2.5 QBTU.

‡ Excludes coking coal which accounted for 1.1 QBTU of coal use in 1990.

Petroleum

The projection coverage of petroleum consumption is limited to use in combustors: process steam and heat in the industrial sector; steam generators in the electric power sector; and space and water heating in the residential and commercial sectors. In this portion of the market, the potential for growth in petroleum consumption is relatively limited and is dependent on the relative price of residual and distillate fuel oil to alternative fuels. In Reference Case 1, petroleum consumption shows no growth between 1990 and 2010, remaining at roughly 5.0 QBTU. It grows modestly between 1990 and 2000, as residual fuel oil consumption is projected to recover from the low levels of 1990, but loses the gains achieved after 2000 as rising oil prices make petroleum less competitive relative to natural gas.

In Reference Case 2, petroleum grows from 5.0 to 5.5 QBTU between 1990 and 2000, or by almost one percent per year. This stems from the improved price competitiveness of petroleum due to the flat oil price assumption. Petroleum gains market share from natural gas in the near term as gas prices increase and as gas supplies and demand come into balance. However, in the post-2000 period, petroleum consumption drops from 5.5 QBTU in 2000 to only 4.5 QBTU by 2010. Much of the loss is in the industrial sector as assumed rapid efficiency improvements and tougher price competition reduce consumption. Petroleum consumption in this Case is also down in the electric power sector as lower economic growth reduces requirements for electricity generation.

Coal

Coal consumption grows from 17.9 QBTU in 1990 to 23.2 QBTU by 2010 in Reference Case 1, or by 1.3 percent per year. Almost all of the growth is for electric power generation. Despite expectations of increased natural gas consumption for power generation, coal is projected to continue to account for the dominant portion of future growth in electricity generation.

Despite lower rates of growth in electricity demand, coal consumption also is projected to grow in Reference Case 2 from 17.9 QBTU in 1990 to 21.0 QBTU by 2010 (0.8 percent per year). Again, the growth in this Case is dominated by increased consumption for electricity generation. In fact, the projection is somewhat misleading. A disproportional amount of the decline in coal consumption by 2010 in Reference Case 2 (relative to Reference Case 1) occurs in the industrial sector. If not for this disproportionate decline, coal consumption growth would be somewhat stronger in this Case.

Nuclear/Hydro

Both Reference Cases assume only the completion of the nuclear power plants currently under construction and the continued operation of those plants that have not been affected by policy restrictions. In the post-2000 period, nuclear consumption declines somewhat due to the assumed retirement of plants at the end of licensing periods. A similar approach is taken toward hydrogenerating plants.

Natural Gas Consumption

Table 8-7 provides a summary of projected total natural gas consumption by sector in the Reference Cases.

The Reference Cases present two very different scenarios of gas demand growth between 1990 and 2010. In Reference Case 1, total gas consumption in the lower-48 states is projected to increase from 18.8 QBTU in 1990 to 24.8 QBTU by 2010, or at 1.4 percent per year. Most of the growth is concentrated in the industrial and electric power sectors. However, growth occurs in all sectors to varying degrees. By contrast, in Reference Case 2, gas consumption shows virtually no growth between 1990 and 2000 and only very modest growth by 2010. In this Case, gas consumption grows from 18.8 QBTU in 1990 to only 20.6 QBTU by 2010. Overall, gas consumption is projected to grow at only 0.5 percent per year. Virtually all of the growth occurs in the electric power sector.

These two Cases represent diametrically opposed points of view both for what they suggest about gas industry planning and for energy markets in general. In Reference Case 1, the growth in gas consumption that began in the mid-1980s is projected to continue (though at somewhat slower rates than recent experience) through 2010. The gas share of total pri-

TABLE 8-7

GAS CONSUMPTION BY SECTOR IN THE LOWER-48 STATES
REFERENCE CASES 1 AND 2
(Quadrillion BTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Residential	4.5	4.9	4.8	4.9	4.7
Natural Gas Vehicles	*	(0.1)	(0.1)	(0.1)	(0.1)
Other	(2.7)	(2.9)	(2.8)	(3.4)	(3.0)
Total Commercial	**2.7**	**3.0**	**2.9**	**3.5**	**3.1**
Boilers	(2.8)	(3.1)	(2.4)	(3.8)	(2.2)
Non-Boilers†	(4.2)	(4.8)	(4.2)	(5.1)	(3.9)
Lease & Plant	(1.1)	(1.1)	(1.0)	(1.3)	(1.1)
Total Industrial	**8.1**	**9.0**	**7.5**	**10.2**	**7.2**
Electric Utility	2.9	3.9	3.2	5.4	4.9
Transportation‡	0.6	0.7	0.7	0.9	0.7
Total	**18.8**	**21.4**	**19.1**	**24.8**	**20.6**

* Less than 50 trillion BTU.

† Includes incremental energy consumption for power generation, process heat, machine drive, and feedstock use of natural gas.

‡ Includes only pipeline transmission use of natural gas.

mary energy consumption (based on the subset shown in Table 8-6) grows from 36.9 percent in 1990 to over 39 percent by 2010. In Reference Case 2, the gas industry has already experienced gas's "high" level of consumption and little change is projected over the next 20 years. The gas share of total primary energy consumption remains flat in this Case at roughly 37 percent through 2010.

Residential Sector

The level of residential gas demand is dominated by space-heating requirements. Based on heating degree day data, the United States has not experienced a completely "normal" winter in six years. In each of these years, the number of heating degree days have been below normal. That is the winters have been warmer than normal. The only cold period experienced in recent years was the abnormally cold weather in December of 1989. This series of warmer than normal winters have made it very difficult to project residential gas demand in the future. The historical data provide little indication of what gas demand would be in a normal winter.

Both Reference Cases assume normal weather conditions. As a result, projected gas consumption between 1990 and 2000 shows a sharp increase in both Cases. The level of consumption shown for the base year, 1990, was severely impacted by warmer than normal weather. A weather normalized level of consumption in 1990 would be close to 4.9 QBTU. Thus, starting from this weather normalized level of consumption, projected residential gas consumption shows virtually no change in either Case between 1990 and 2010. Growth in the number of gas-using homes is projected to be completely offset by continued improvement in the efficiency of the stock of gas-fired equipment as older, less efficient systems are replaced by more efficient equipment.

Commercial Sector

The commercial sector represents a potential growth market for natural gas. The entire potential for growth in gas consumption in the commercial sector rests on the success of gas-fired commercial space cooling and cogeneration systems. The tightening of the thermal shell of commercial buildings has made space cooling the primary determinant of the space conditioning fuel choice in commercial buildings. Gas currently meets a very small share of the space cooling load in the commercial sector. Gas is used for space cooling in only about 4 percent of total commercial square footage. The major potential for gas demand growth in the sector lies in capturing a large share of this space cooling market through the use of improved technologies—cogeneration, gas-fired heat pumps, gas engine driven chillers, and absorption systems.

Reference Case 1 assumes the introduction of only those new gas space cooling technologies that are close to commercialization. However, it does not assume the introduction of any revolutionary new technologies. This is a relatively conservative technology assumption that limits gas's ability to compete with other fuels whose technologies are assumed to continue to improve. Despite this assumption, in Reference Case 1 commercial gas consumption grows from 2.7 QBTU in 1990 to 3.5 QBTU by 2010. Growth is stronger in the post-2000 period as commercial construction recovers from the overbuilding of the 1980s.

Reference Case 2 adopts a more limiting assumption about the introduction of new gas space cooling technologies. In this Case, new gas technologies not already in the market are not introduced as gas options in the projection. This is a very conservative technology assumption and puts gas at a disadvantage relative to other fuels, particularly electricity. This conservative technology assumption combined with the lower economic growth assumed in this Case holds down gas consumption growth. Natural gas consumption is projected to increase from 2.7 QBTU in 1990 to 3.1 QBTU by 2010.

The projection includes natural gas consumption by vehicles in the commercial sector. Both Reference Cases include a very conservative assumption of growth in the number of natural gas-fueled vehicles. Penetration is limited to the clean-fuel vehicle programs for fleet vehicles that are mandated by the Clean Air Act Amendments of 1990. By 2010, vehicle consumption of natural gas is 140 trillion BTU (or about 0.1 QBTU) in both Reference Cases.

Industrial Sector

The most significant impact of the different assumptions made in the Reference Cases shows up in the industrial sector projections. Assumptions made about three factors—industrial production growth, oil prices, and energy intensity improvement—made these Cases significantly different. In Reference Case 1, industrial production was assumed to grow at 2.7 percent per year between 1990 and 2010, crude oil prices rose to about $28.00 per barrel by 2010, and the energy intensity improvement trends were set roughly consistent with the trends between 1983 and 1990. In Reference Case 2, industrial production is assumed to grow at a slower 2.25 percent per year, crude oil prices remain flat in real dollars, and the energy intensity improvement trends are set consistent with the experience between 1973 and 1980.

The net result of these differences is that natural gas consumption increases strongly in Reference Case 1 from 8.1 QBTU in 1990 to 10.2 QBTU by 2010, or at 1.2 percent per year. The growth is evenly distributed between boiler and non-boiler applications. Boiler gas consumption is projected to grow from 2.8 QBTU in 1990 to 3.8 QBTU by 2010. Non-boiler consumption increases from 4.2 QBTU in 1990 to 5.1 QBTU by 2010. Non-boiler gas consumption includes incremental energy consumption for power generation. Incremental consumption refers to only the net increase in energy consumed due to the generation of electricity; it excludes the energy consumed for the raising of steam which is included in boiler consumption.

In Reference Case 2, natural gas consumption falls from 8.1 QBTU in 1990 to 7.2 QBTU by 2010. The assumed relatively strong rate of energy intensity improvement (based on the trends between 1973 and 1980) is sufficient to completely offset the slower rate of industrial production growth. Furthermore, gas faces a tougher competitive position in markets as a result of the assumption of flat real oil prices. In this Case, boiler gas consumption declines from 2.8 QBTU in 1990 to only 2.2 QBTU by 2010. Non-boiler consumption of natural gas also declines but by a smaller amount, from 4.2 QBTU in 1990 to 3.9 QBTU by 2010. Non-boiler gas consumption is supported, somewhat, by the continued growth in gas-fired cogeneration.

Electric Power Sector

In 1990, gas consumption for electric power generation (both by central electric utilities and independent power producers) accounts for only 2.9 QBTU of total lower-48 gas consumption, just under 16 percent. However, this source holds the greatest potential for growth in gas consumption. Gas has a number of major advantages in electric power generation—short construction lead-time, clean burning, low capital investment, efficient equipment—that promote increased use. Further, the increasing emphasis on the environment also supports the increased use of natural gas. However, to achieve this potential requires that gas overcome numerous barriers to increased use, including utility reluctance to rely on gas, concerns about supply adequacy, the need to expand and improve the gas delivery infrastructure, and fears of a gas price run-up once the gas bubble ends.

In Reference Case 1, gas consumption is projected to increase from 2.9 QBTU in 1990 to 5.4 QBTU by 2010. This growth is based on growth in purchased electricity of 1.6 percent per year and includes the repowering of 21 gigawatts of capacity to gas-firing. In Reference Case 2, gas consumption grows slightly slower from 2.9 QBTU in 1990 to 4.9 QBTU by 2010. In this Case, purchased electricity is assumed to only grow at 1.3 percent per year, and a smaller 15 gigawatts of capacity is repowered using gas. Furthermore, this Case assumes that a larger share of new coal-fired generating units are built at existing sites. To reflect this, Reference Case 2 assumes lower capital costs for new coal-fired units improving the competitive position of coal relative to gas. The level of gas consumption would have been even lower in this Case if not for projected lower gas price levels that help gas maintain market share.

Transportation Sector

The projection only includes gas consumption for pipeline compressor use in the transportation sector. Gas consumption by vehicles is included in the commercial sector. Pipeline compressor consumption of natural gas varies roughly proportional to the total throughput in interstate pipelines. In Reference Case 1, pipeline compressor consumption of natural gas is projected to grow from 0.6 QBTU in 1990 to 0.9 QBTU in 2010. In Reference Case 2, pipeline compressor consumption of natural gas grows to a smaller 0.7 QBTU by 2010.

RESIDENTIAL SECTOR

Economic and Energy Assumptions

Table 8-8 summarizes the key economic and energy assumptions made for the residential sector in the Reference Cases. Reference

TABLE 8-8

RESIDENTIAL SECTOR ECONOMIC AND ENERGY ASSUMPTIONS
(Percent Change Per Year: 1990 to 2010)

	Reference Case 1	Reference Case 2
Population Growth	0.64	0.31
Housing Stock Growth	1.01	0.74
Disposable Income	1.80	1.49
Electricity Demand*	1.65	1.08
Energy Intensity*,†	-0.50	-0.60

* Targeted change, may not be consistent with final projection.

† Energy use per unit (building, sq. ft. of floor space).

Case 1 assumes a more optimistic outlook with stronger growth in population, housing stock, disposable income, and electricity demand than Reference Case 2. The rate of change of energy intensity per residential unit declines somewhat more rapidly in Reference Case 2 when compared with Reference Case 1, implying a greater rate of energy efficiency improvement.

Energy Prices

Table 8-9 compares the residential energy prices in the Reference Cases. On the basis of the price of a BTU of delivered energy, the competitiveness of natural gas worsens relative to both electricity and distillate fuel oil in the Reference Cases. Between 1990 and 2010, natural gas prices are projected to grow by 1.1 percent per year in Reference Case 1 and by 1.0 percent per year in Reference Case 2. By comparison, over the same period, electricity prices are projected to grow by a slower 0.1 percent per year in Reference Case 1 and to actually decline by 0.1 percent per year in Reference Case 2. Projected distillate fuel oil prices grow at 0.6 percent per year in Reference Case 1 and decline at a rate of 0.3 percent per year in Reference Case 2 between 1990 and 2010. However, since natural gas starts from a much lower price in the base year, it is projected to maintain a BTU delivered price advantage over both electricity and distillate fuel oil despite its projected more rapid price growth.

The major competitor to gas in the residential sector is electricity. The higher relative efficiencies inherent in electric equipment, in particular the heat pump (typically in excess of 300 percent for both heating and cooling), offsets much of the price advantage that gas has relative to electricity. In 1990, the electric to natural gas price ratio was 4.1:1. Gas prices are projected to rise rapidly in the near term due to the end of the gas bubble. As a result, the ratio falls in both Reference Cases to 3.4:1 by 2000. The ratio is projected to decline further between 2000 and 2010, reaching 3.3:1 by 2010. The decline in the electric to gas price ratio worsens gas's competitive position relative to electricity, which is reflected in a decline in the gas share of total residential energy consumption and an increase in the electric share of total consumption.

Energy Consumption

Total residential energy demand grew from 6.2 QBTU in 1960 to 9.8 QBTU by 1972, or at a rate of 3.9 percent per year. In response to the increased emphasis on conservation following the oil price spike of the early 1970s, residential energy consumption declined from 9.8 QBTU in 1972 to a low of 8.4 QBTU by 1983. Since 1983, residential energy consumption has resumed growth, but at a slower rate than experienced from 1960 to 1972. Total consumption has grown from 8.4 QBTU in 1983 to 9.0 QBTU in 1990, or at 0.9 percent per year.

Natural gas accounts for the largest portion, 50 percent, of total residential energy consumption in 1990. Electricity, the second most important energy source, accounts for 35 percent of consumption in 1990. Distillate fuel oil accounts for 10 percent, and liquefied petroleum gases for 4 percent. Coal accounts for the remaining 1 percent.

Table 8-10 compares residential energy consumption in the Reference Cases. Total residential energy consumption is projected to

TABLE 8-9

**RESIDENTIAL SECTOR ENERGY PRICES IN THE LOWER-48 STATES
REFERENCE CASES 1 AND 2
(1990$/MMBTU)**

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Natural Gas	5.65	6.81	6.48	6.99	6.83
Electricity	23.02	22.80	22.05	23.27	22.70
Distillate Fuel Oil	7.66	7.45	6.75	8.62	7.26

TABLE 8-10

RESIDENTIAL SECTOR ENERGY CONSUMPTION IN THE LOWER-48 STATES
REFERENCE CASES 1 AND 2
(Quadrillion BTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Natural Gas	4.5	4.9	4.8	4.9	4.7
Electricity	3.1	3.7	3.5	4.4	3.9
Distillate Fuel Oil	0.9	0.8	0.9	0.7	0.7
Liquefied Petroleum Gases	0.4	0.3	0.3	0.3	0.3
Coal	0.1	0.1	0.1	0.1	0.1
Total	**9.0**	**9.8**	**9.6**	**10.4**	**9.6**

grow slowly over the projection and at rates slower than recent history. This results from projected slow growth in population and in the housing stock, and continued improvement in energy efficiency. Between 1990 and 2010, total energy demand is projected to grow at an annual rate of 0.7 percent per year in Reference Case 1 and 0.4 percent per year in Reference Case 2.

Natural gas consumption is projected to grow at 0.5 percent per year in Reference Case 1 and a slower 0.2 percent per year in Reference Case 2. The gas share of total residential energy consumption is projected to fall from 50 percent in 1990 to only 47 percent in Reference Case 1 and 49 percent in Reference Case 2 by 2010.

Electricity consumption is projected to grow more rapidly than any other fuel in both Cases. Electricity consumption is projected to grow by 1.6 percent per year between 1990 and 2010 in Reference Case 1 and by 1.1 percent per year in Reference Case 2. Both rates of growth are considerably slower than recent historical experience. Between 1980 and 1990 residential electricity consumption grew at 2.5 percent per year. However, the rate of growth in residential electricity usage has progressively slowed in each decade since World War II and the increased expenditures on DSM by electric utilities are expected to impact future growth rates. Despite the modest rate of growth, the electricity share of total residential energy consumption grows in both Cases from 34 percent in 1990 to 43 percent by 2010 in Case 1 and 41 percent in 2010 in Case 2.

Distillate fuel oil consumption is projected to decline in both Cases from 0.9 QBTU in 1990 to 0.7 QBTU by 2010. Distillate fuel oil is predominantly used for space heating in regions of the U.S. that developed the earliest (the Northeast and Central states) and in locations where natural gas was not available. The cost of distillate fuel oil for heating is generally higher relative to other fuels; it is dirtier and is generally perceived not to offer the convenience of either natural gas or electricity. As a result, it has fallen out of favor for space heating in the United States and its share of total residential energy consumption and space heating is projected to decline in the future.

Liquefied petroleum gas (LPG) consumption is projected to decline from 0.4 QBTU in 1990 to 0.3 QBTU by 2010 in both Cases. LPG is used predominantly in rural areas where natural gas is not available or where natural gas hookup charges are prohibitive. LPG is generally more expensive than either natural gas and distillate fuel oil and, as a result, its growth is expected to be limited in the future.

Gas Consumption

Figure 8-5 shows a comparison of total energy and natural gas demand in both Cases. Gas consumption in the residential sector is dominated by consumption for space heating. In 1990, gas consumption for space heating represented over 70 percent of total residential gas consumption. About 20 percent of residential gas consumption is for water heating. An additional 4 percent is consumed for cooking.

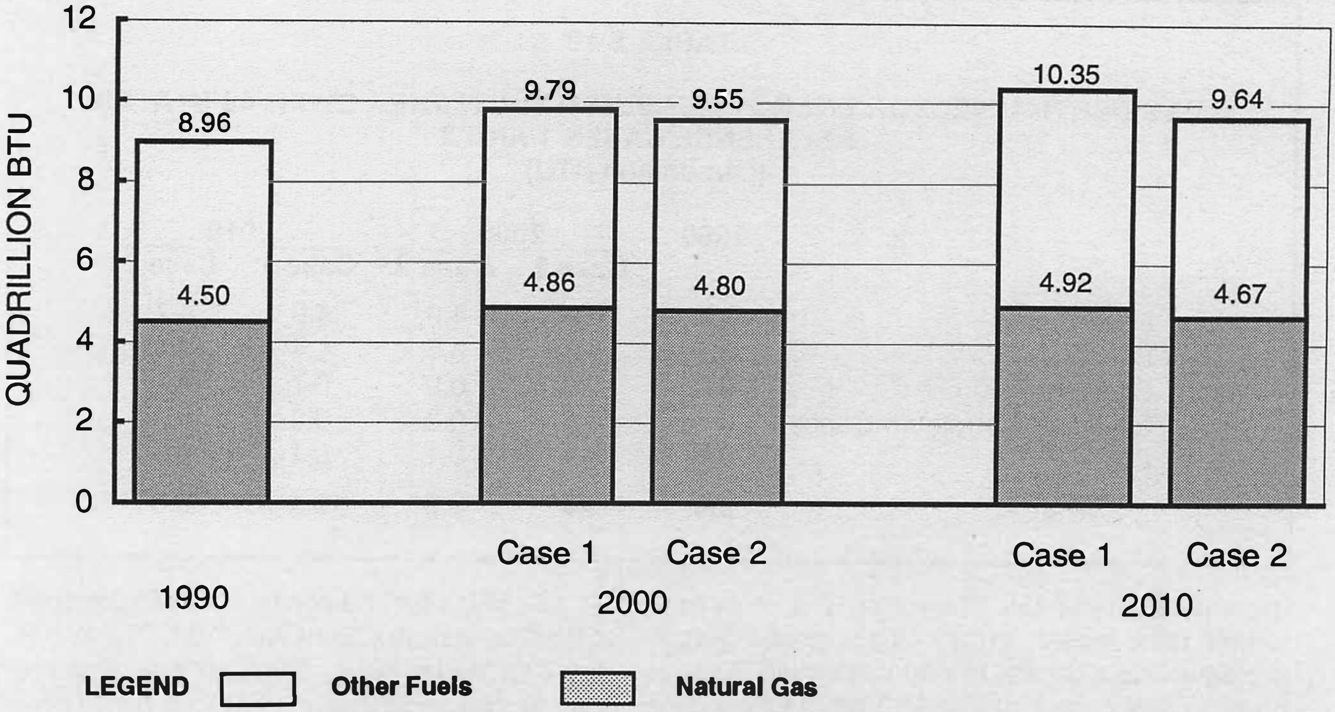

Figure 8-5. Residential Energy Demand—Reference Cases 1 and 2.

The remaining 2 percent is used predominately for clothes drying and space cooling.

Residential gas consumption shown for 1990 is actual consumption. Because of the large share of residential gas consumption attributable to space heating, the level of gas consumption is very sensitive to weather. Space heating loads were relatively low in 1990 due to abnormally warm weather over the year. As a result, gas consumption was also low. As highlighted earlier, the projection uses weather normalized data. Consumption in 1990 would have been about 4.9 QBTU in a weather normal year. Starting from this weather normalized level, gas consumption shows no increase in Reference Case 1 through 2010 and a small decline in Reference Case 2.

Efficiency improvements in both new and replacement equipment, as well as improvement in the thermal integrity of homes, offsets much of the impact on gas demand of the increase in the number of gas customers. The average efficiency of a new gas-fired furnace, which was approximately 76 percent in 1990, will likely increase to almost 90 percent by 2010 to meet the requirements under phase two of the National Appliance Energy Conservation Act. With the replacement of older furnaces and the construction of new homes using more efficient furnaces, the average efficiency of the stock of gas-fired furnaces will increase significantly from the average of 66 in 1990. Over the same period, building shell thermal integrity is projected to improve significantly. Combined, these two conservation improvements will have the impact of reducing gas consumption significantly relative to what would have been required using today's technologies.

One of the keys to increasing residential gas demand in the future is the space cooling market. Gas-fired space cooling holds a very small share of residential energy consumption for space cooling in 1990. The development of a successful gas-fired heat pump or space cooling system could make a significant contribution to increasing the level of gas demand in the residential sector. Reference Case 1 assumes the introduction of a gas-fired heat pump, however, it does not assume the introduction of a conventional gas-fired space cooling system or aggressive improvement in the efficiency or first cost of the heat pump. Therefore, the heat pump has very little impact on the residential sector results. The heat pump is not assumed to be introduced in Reference

Case 2 at all. As a result, no viable gas-fired space cooling option is available in the Case. This is a partial explanation for the more moderate growth in gas consumption in Reference Case 2.

The scenarios also focus attention on the need for the gas industry to maintain gas's share of the existing market through the development of new and improved competitive equipment and the continued offering of competitive prices. In 1990 there were almost 48 million gas space heating customers. To maintain gas's space heating market share, gas equipment must be able to compete on the basis of cost and efficiency with other systems. This need is underscored by the large replacement market for gas-fired equipment, consisting of well over 2 million gas-fired space heating systems projected to annually come up for replacement over the projection period. This compares to total new home sales (all fuels) averaging only about 1.6 million units per year.

COMMERCIAL SECTOR

Economic and Energy Assumptions

Table 8-11 summarizes the key economic and energy assumptions made for the commercial sector in the Reference Cases. Reference Case 1 assumes a more optimistic outlook with stronger growth in commercial floor space and electricity demand than Reference Case 2. The rate of change of energy intensity per commercial unit declines at the same rate in both Cases indicating the same rate of efficiency improvement. A modest penetration of new gas technologies is assumed in Reference Case 1, whereas no growth in new gas technologies is assumed in Reference Case 2.

Energy Prices

Table 8-12 compares the commercial sector energy prices in the Reference Cases. As was the situation in the residential sector, on the basis of the price of a BTU of delivered energy, the competitiveness of natural gas in the commercial sector worsens relative to both electricity and distillate fuel oil in the Reference Cases. Commercial sector natural gas prices are projected to grow by 1.3 percent per year in Reference Case 1 and by 1.1 percent per year in Reference Case 2 between 1990 and 2010. Over the same period, electricity prices are projected to show no significant growth in Reference Case 1 and to decline by 0.1 percent per year in Reference Case 2. Distillate fuel oil prices grow at 0.7 percent per year in Reference Case 1 and decline by 0.3 percent per year in Reference Case 2. Natural gas maintains a BTU price advantage over electricity in both Cases owing to the very high price of electricity in the base year. However, natural gas is projected to lose its price advantage over distillate fuel oil by the year 2000 in both Cases. Distillate fuel oil prices are projected to grow rapidly between 2000 and 2010 in Reference Case 1 and gas regains its price advantage. In Reference Case 2, however, distillate fuel oil prices are projected to remain below gas prices through 2010.

TABLE 8-11

COMMERCIAL SECTOR ECONOMIC AND ENERGY ASSUMPTIONS
(Percent Change Per Year: 1990 to 2010)

	Reference Case 1	Reference Case 2
Commercial Floor Space	1.40	1.08
Electricity Demand	1.45	1.30
Energy Intensity*,†	-0.40	-0.40
New Gas Technologies	Modest Penetration	No Incremental Penetration

* Targeted change, may not be consistent with final projection.

† Energy use per unit (building, sq. ft. of floor space).

TABLE 8-12

COMMERCIAL SECTOR ENERGY PRICES IN THE LOWER-48 STATES
REFERENCE CASES 1 AND 2
(1990$/MMBTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Natural Gas	4.72	5.94	5.56	6.17	5.92
Electricity	21.51	20.88	20.64	21.69	21.11
Distillate Fuel Oil	5.99	5.78	5.07	6.94	5.59

The improved competitive position of distillate fuel oil, particularly in Reference Case 2, is of little consequence. While the major portion of current gas consumption in the commercial sector is for space heating, the dominant portion of future energy demand growth in the sector will be for space cooling or non-space conditioning applications. Distillate fuel oil has little potential to serve either of these loads. Like the residential sector, the major competitor to gas in the commercial sector is electricity. In 1990, the electric to natural gas price ratio was 4.6:1. The ratio is projected to fall to 3.5:1 in Reference Case 1 and to 3.7:1 in Reference Case 2 by 2000. By 2010, the ratio falls to 3.5:1 in Reference Case 1 and to 3.6:1 in Reference Case 2.

Energy Consumption

Total commercial energy demand grew rapidly in the 1960s from 3.3 QBTU in 1960 to 5.3 QBTU by 1970, or at 4.9 percent per year. Since 1970, growth in commercial energy consumption has slowed considerably to an average rate of about 1.0 percent per year.

Energy consumption in the commercial sector is dominated by natural gas and electricity. Electricity accounts for the largest portion, 44 percent of total commercial energy consumption in 1990. Natural gas, the second most important energy source, accounts for 42 percent of consumption in 1990. Together, distillate, LPG, and residual fuel account for 12.5 percent. Coal accounts for the remaining 1.5 percent.

Since 1960, commercial consumption of coal and petroleum products has been declining, while consumption of electricity and natural gas has been steadily growing. Both coal and petroleum have been losing share of total consumption to electricity and natural gas during this time.

Table 8-13 provides a comparison of projected commercial sector energy consumption in the Reference Cases. Between 1990 and 2010, total commercial energy consumption grows at an annual rate of 1.2 percent in Reference Case 1 and a slower 0.9 percent per year in Reference Case 2. However, growth in commercial energy consumption does not take place evenly over the entire projection time frame. The main determinant of commercial energy consumption growth is growth in square footage. Commercial square footage grows more slowly during the 1990s as the sector absorbs the overbuilding of the 1980s. As a result, total commercial energy consumption is projected to grow by 0.9 percent per year in Reference Case 1 and by 0.6 percent per year in Reference Case 2 between 1990 and 2000. Between 2000 and 2010, total energy consumption is projected to grow by 1.5 percent per year in Reference Case 1 and by 1.1 percent per year in Reference Case 2.

Natural gas consumption is projected to grow at 1.3 percent per year in Reference Case 1 and a slower 0.7 percent per year in Reference Case 2. The gas share of total commercial energy consumption is projected to remain relatively constant at roughly 42 percent between 1990 and 2010 in Reference Case 1 and to fall to about 40 percent by 2010 in Reference Case 2.

Projected commercial sector electricity consumption is almost identical in both Cases. Electricity consumption grows from 2.9 QBTU in 1990 to 3.8 QBTU in Reference Case 1 and 3.7 QBTU in Reference Case 2 by 2010. Without the availability in Reference Case 2 of a gas option for space cooling based on the technology assumption, electricity captures virtually the entire space cooling load which holds up electricity consumption despite the slower growth in commercial square footage. This explicitly illustrates the importance of the technology assumptions.

Petroleum consumption (distillate fuel oil, residual fuel oil, and liquefied petroleum gases) is projected to remain virtually unchanged between 1990 and 2010 in both Cases. Petroleum consumption is constrained to space heating predominantly in older buildings. With limited growth in requirements for space heating, the prospect for growth in petroleum consumption is limited. The improvement in the relative price of petroleum products results in no net market share gain.

Natural Gas Consumption

Total Consumption

Figure 8-6 provides a comparison of total energy and natural gas demand from both Cases. Commercial sector gas consumption grew steadily through the early 1970s, peaking at 2.7 QBTU in 1972. With strong increases in energy prices, an increased emphasis on conservation, and a rapid succession of economic downturns, growth in commercial gas consumption stagnated for the balance of the 1970s and 1980s. The level of consumption has varied on a year-to-year basis, but it has generally ranged between 2.5 and 2.7 QBTU. Both Reference Cases show growth in commercial gas consumption resuming during the 1990s.

Natural gas is consumed in the commercial sector predominantly for space heating. In 1990, just over 50 percent of the gas consumed in the commercial sector was for space heating. Substantial quantities of natural gas are also consumed for water heating, cogeneration, and miscellaneous applications, which include cooking, process heat, and miscellaneous uses. Water heating accounts for about 5 percent of gas consumption, cogeneration about 7 percent, and other applications 35 percent. Small amounts of natural gas are also consumed in the commercial sector for space cooling, predominantly in existing absorption systems. Gas consumption for space cooling accounts for only a little over 1 percent of total commercial gas consumption.

The most important single long-term factor driving commercial gas demand growth in the future will be the successful penetration of new space cooling and cogeneration technologies. Because of gas's relatively small share of the current commercial space cooling market, this technology represents a potential growth market for natural gas.

The projections of natural gas consumption diverge significantly in the Reference Cases. The major source of this difference is the technology assumption made in each Case and the assumed level of commercial square footage growth. As already highlighted, Reference Case 1 assumes the introduction of only

TABLE 8-13

**COMMERCIAL SECTOR ENERGY CONSUMPTION IN THE LOWER-48 STATES
REFERENCE CASES 1 AND 2
(Quadrillion BTU)**

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Natural Gas	2.7	3.0	2.9	3.5	3.1
Electricity	2.9	3.3	3.2	3.8	3.7
Distillate Fuel Oil	0.5	0.5	0.5	0.6	0.5
Residual Fuel Oil	0.2	0.2	0.2	0.2	0.2
Liquefied Petroleum Gases	0.1	0.1	0.1	0.1	0.1
Coal	0.1	0.1	0.1	0.1	0.1
Total	**6.5**	**7.1**	**6.9**	**8.2**	**7.7**

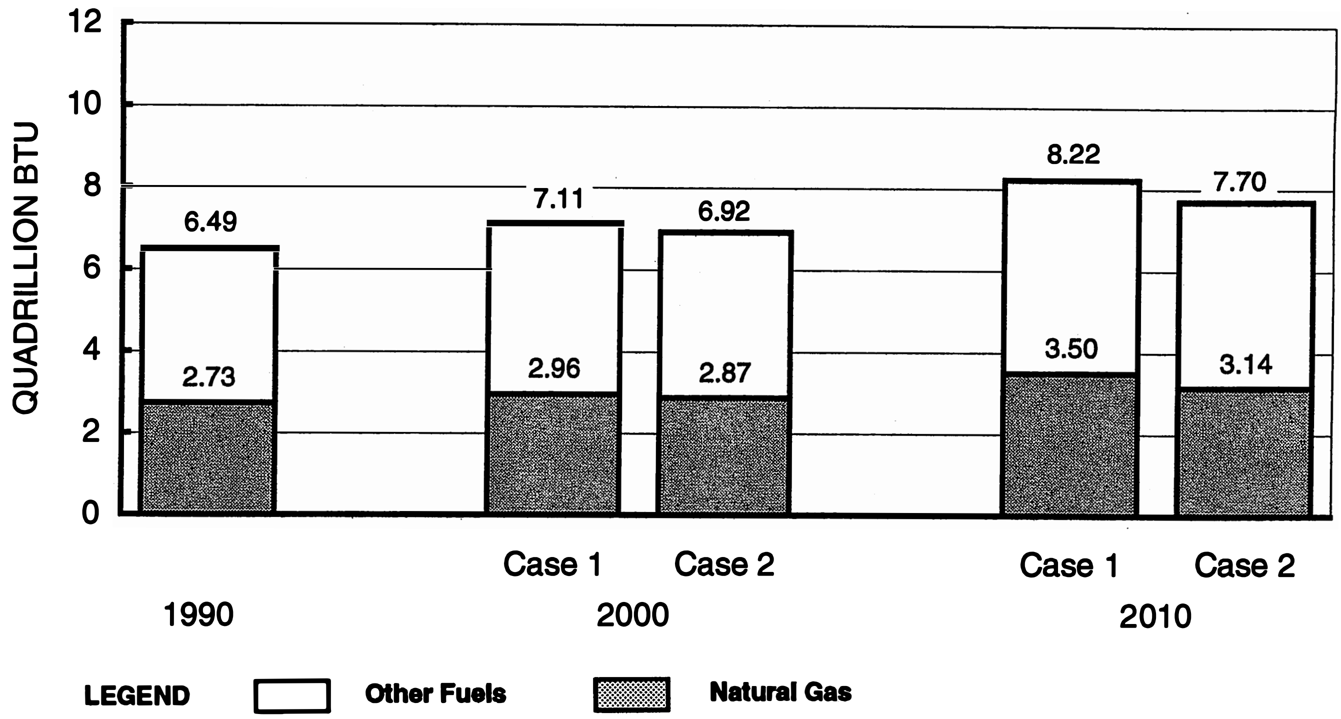

Figure 8-6. Commercial Energy Demand—Reference Cases 1 and 2.

those new gas space cooling technologies. This implies the introduction of a gas heat pump as well as the introduction of an advanced double-effect absorption chiller and advanced engine-driven systems. Reference Case 2 adopts a more limiting technology assumption about new gas-fired space cooling systems. In this Case, new gas technologies including the gas heat pump are not introduced as gas options in the projection. This is a very conservative technology assumption and puts gas at a disadvantage relative to other fuels, particularly electricity.

The second contributing factor to the divergent projections of gas consumption is the lower assumed rate of growth in commercial square footage. In Reference Case 1 commercial square footage is assumed to grow at 1.4 percent per year between 1990 and 2010. In Reference Case 2 it is assumed to grow at a slower 1.08 percent per year. With this assumption, total commercial square footage is over 6 percent lower by 2010 in Reference Case 2 when compared with Reference Case 1.

As a result of differences in the assumptions about technology and growth in square footage, gas consumption growth in the two Cases is very different. In Reference Case 1 gas consumption is projected to grow from 2.7 QBTU in 1990 to 3.5 QBTU by 2010, or at 1.3 percent per year. However, with the more limiting technology assumption and a reduced rate of growth in commercial square footage, gas consumption only grows to 3.1 QBTU by 2010 in Reference Case 2 or by 0.7 percent per year.

Natural Gas Vehicles

The projection of natural gas consumption in vehicles is included in the commercial sector. The penetration of gas in vehicles was developed exogenously to the model through an off-line analysis. The projected level of natural gas consumption in vehicles was identical in both Reference Cases.

The analysis only considers vehicles mandated by the Clean Air Act Amendments of 1990 or California statutes to use clean fuels. As such, the analysis is a conservative estimate of natural gas use in vehicles. A number of other states have adopted California-like statutes since the analysis was done and the enacting legislation from the Clean Air Act Amendments is still being developed.

The first step in the analysis was determining the estimated universe of potential vehicles and demand under the program. Four vehicle groups were targeted under the clean fuels program: urban buses, fleet vehicles, private vehicles (California only), and some heavy-duty trucks. Since this is a projection of future consumption it is important to consider how the existing population will change. The important determinants of the dynamics include:

- Vehicles in operation
- Miles of travel
- Fuel consumption by vehicle type
- Vehicle lifetime
- Extent of U.S. vehicle population in affected geographic areas
- New vehicle sales level
- Limiting provisions under the Amendments (e.g., fleet vehicle program limited to centrally-fueled fleets of 10 or more).

With these considerations, a potential clean-fuel level of consumption was estimated by vehicle type over time. This is the potential energy consumption in the affected clean-fuel vehicle populations. Table 8-14 shows the estimated potential level of consumption in clean-fuel vehicles.

Once the potential population and implied demand is identified, the penetration of natural gas vehicles (NGVs) into the population was determined. Natural gas is not the only clean fuel available. It is unlikely that natural gas will capture the entire clean-fuel vehicle market. For this analysis a fairly positive outlook for NGV penetration was assumed as follows:

- 25 percent of urban buses
- 25 percent of fleet vehicles
- 10 percent in California of the pilot program for private vehicles
- 50 percent of other vehicle groups (e.g., school buses and heavy trucks).

Based on these penetration assumptions, Table 8-15 shows the projection of natural gas consumption in vehicles.

INDUSTRIAL SECTOR

Economic and Energy Assumptions

Table 8-16 summarizes the key economic and energy assumptions made for the industrial sector in the Reference Cases.

Reference Case 1 includes a more optimistic outlook for industrial production growth and electricity demand than Reference Case 2. In both Cases, the change in the relative mix of production by Standard Industrial Classification (SIC) is assumed to continue based on the trends observed during the period from 1983 to 1990 (this was previously discussed in the General Assumption discussion on projection philosophy). Energy intensity improvement is also assumed to continue along the trends seen during the 1980s in Reference Case 1. However, in Reference Case 2 energy intensity improvement is assumed to take place at the faster rate seen between 1973 and 1980 (this was previously discussed in the General Assumption discussion on projection philosophy).

TABLE 8-14

POTENTIAL CLEAN-FUEL VEHICLE ENERGY CONSUMPTION
(Trillion BTU)

	1990	2000	2010
Urban Buses	0.0	19.8	54.9
School Buses	0.0	2.6	25.1
Fleet LDV/LDT	0.0	80.2	194.9
California Pilot Program	0.0	116.3	244.3
Lt/Med HDTs	0.0	23.3	81.3
Other LDV/LDT	0.0	0.0	0.0
Total	**0.0**	**242.2**	**600.5**

TABLE 8-15

COMPRESSED NATURAL GAS VEHICLE
NATURAL GAS CONSUMPTION SCENARIO
(Trillion BTU)

	1990	2000	2010
Urban Buses	0.0	5.0	13.7
School Buses	0.0	1.3	12.6
Fleet LDV/LDT	0.0	20.1	48.7
California Pilot Program	0.0	11.6	24.4
Lt/Med HDTs	0.0	11.7	40.7
Other LDV/LDT	0.0	0.0	0.0
Total	**0.0**	49.6	140.1

The projection of industrial cogeneration in Reference Case 1 was based on the projection in the 1993 Edition of the GRI Baseline Projection. The projected level of cogeneration in Reference Case 2 was reduced to reflect the lower steam demand in that Case.

Industrial production is a particularly important determinant of industrial energy consumption growth. However, an aggregate measure of industrial production growth is not adequate as a determinant of energy demand growth in a long-run projection because of variation in the mix of processes and differences in energy intensity by industry. The EEA model explicitly uses industrial production growth by the nine industry categories shown in Table 8-17. However, this section will only discuss total industrial energy consumption and not consumption by industry.

Energy Prices

Table 8-18 compares the industrial sector energy prices in the Reference Cases. Starting in August 1990 there was a spike in crude oil and petroleum product prices in response to the Iraq invasion of Kuwait. As a result, the average price of petroleum products in 1990 was artificially inflated by events during that year. By contrast, natural gas prices did not generally respond to the spike in petroleum product prices but simply continued the gradual price erosion that began in the early 1980s as a result of the gas bubble. The rate of growth between 1990 and 2010 in delivered industrial energy prices in Reference Case 1 reflect these cir-

TABLE 8-16

INDUSTRIAL SECTOR ECONOMIC AND ENERGY ASSUMPTIONS
(Percent Change Per Year: 1990 to 2010)

	Reference Case 1	Reference Case 2
Population Growth	2.70	2.25
SIC Mix Of Production	1983-90 Trends	1983-90 Trends
Electricity Demand	1.7	1.5
Energy Efficiency Gains	1983-90 Trends	1973-80 Trends
Industrial Cogeneration	EEA Scenario For The 1993 GRI Baseline Projection	Minor Downward Adjustment In Growth To Match Slower Steam Demand Growth

TABLE 8-17

GROWTH IN INDUSTRIAL PRODUCTION BY INDUSTRY
(Percent Change Per Year: 1990 to 2010)

	Growth Rate	
Industry Group	**Reference Case 1**	**Reference Case 2**
Food	2.7	2.1
Textiles	1.8	1.4
Paper	3.0	2.3
Chemicals	4.1	3.2
Refining	2.1	1.7
Stone, Clay & Glass	2.0	1.8
Steel	1.3	1.0
Aluminum	3.0	2.3
All Other	2.6	2.3
Total	**2.7**	**2.25**

cumstances. As the gas bubble ends, natural gas prices in Reference Case 1 are projected to increase relatively rapidly, by 4.0 percent per year between 1990 and 2000, and petroleum product prices are projected to decline. In Reference Case 1, over the entire projection period, natural gas prices are projected to increase at 2.9 percent per year and residual and distillate fuel oil prices are both projected to increase at roughly 1.2 percent per year.

Despite the faster projected growth in the price of natural gas, it remains competitive with both residual and distillate fuel oil through 2010 in Reference Case 1. Gas prices are projected to remain significantly below distillate fuel oil prices over the entire projection and remain

TABLE 8-18

INDUSTRIAL SECTOR ENERGY PRICES IN THE LOWER-48 STATES
REFERENCE CASES 1 AND 2
(1990$/MMBTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Natural Gas	2.50	3.70	2.50	4.44	3.65
Residual Fuel Oil					
2.0% Sulfur	3.27	3.03	2.36	4.21	2.92
1.3% Sulfur	3.40	3.16	2.49	4.30	3.04
0.7% Sulfur	3.64	3.40	2.71	4.59	3.28
0.3% Sulfur	3.89	3.74	3.06	4.92	3.62
Distillate Fuel Oil	5.18	5.00	4.27	6.58	5.19
Coal					
High Sulfur	1.54	1.46	1.39	1.43	1.35
Low Sulfur	1.67	1.85	1.70	1.88	1.75
Electricity	14.07	14.03	13.76	14.80	14.24

competitive with both 0.7 and 0.3 percent sulfur residual fuel oil. However, gas prices are not projected to remain below the price of 2.0 percent and 1.3 percent sulfur residual fuel oil in the future. The gas price advantage that exists today relative to these two grades of residual fuel oil is a function of the gas bubble. However, with growing restrictions on SO2 emissions, continued consumption of these two grades of residual fuel oil will require expensive equipment modifications, the purchase of emissions credits, or offsets. A strict comparison of the BTU delivered price of the fuels to gas is, therefore, not a fair measure of relative competitiveness.

In Reference Case 2, the scenario assumptions significantly impact the near-term energy price tracks. Crude oil prices are assumed to remain flat at $20 per barrel (which is lower than the average price in 1990) over the entire projection period and, as a result, petroleum product prices decline relative to the prices in 1990. Petroleum product prices, in general, decline by about 0.6 percent per year between 1990 and 2000. Because of the lower petroleum product prices and other constraints on gas consumption, natural gas prices do not increase from 1990 levels through 2000 in Reference Case 2. In effect, the gas supply bubble is extended through the year 2000. After 2000, however, as gas consumption begins to grow (primarily in the electric power sector) gas prices are projected to increase and supplies become tighter. While petroleum product prices do increase somewhat over the same period, they increase at rates slower than the price of natural gas. On a BTU basis, petroleum products appear to improve competitively versus natural gas. However, as was the case in Reference Case 1, with tightening emissions restrictions, price is not necessarily an accurate measure of competitiveness.

In both Reference Cases, based on the BTU delivered price of the fuels, gas's competitiveness declines relative to coal. In Reference Case 1, high sulfur coal prices decline by 0.4 percent per year between 1990 and 2010 and low sulfur coal prices increase at only 0.6 percent per year. In Reference Case 2, high sulfur coal prices are projected to decline at 0.7 percent per year between 1990 and 2010 and low sulfur coal prices are projected to increase at only 0.2 percent per year. Over the same period, natural gas prices are projected to increase by 2.9 percent per year in Reference Case 1 and by 1.9 percent per year in Reference Case 2. Part of the reason for the decline in high sulfur coal prices is the growing number of constraints on high sulfur coal use due to tougher emission standards. This has the effect of creating a high sulfur coal supply surplus. As has been the case throughout this analysis, a comparison of strictly the BTU delivered price of various fuels may not be a good relative measure of competitiveness. Other non-price considerations, which may impact the users' absolute ability to use the fuel or the capital investment required, need to be considered as well.

The real price of electricity is projected to remain flat in both Reference Cases. Electricity prices are projected to grow only at the rate of inflation. Therefore, electricity's competitiveness, on a relative BTU basis, improves relative to natural gas in both Cases. This does not necessarily imply that electricity gains an absolute competitive advantage relative to natural gas in the industrial sector. First, electricity and natural gas do not compete directly for many markets. Electricity is not generally used in boiler applications and is not used in many process heat applications. Further, electricity cannot be used as a feedstock. Second, despite the slower projected rate of growth, electricity prices remain much higher on a BTU basis than other fuels; between 3 and 4 times higher than natural gas by 2010. The difference in fuel price needs to be compensated for by higher equipment efficiency, lower capital costs, reduced emissions (or simpler compliance), or some other attribute. Therefore, while electricity prices become more competitive relative to natural gas, it is not clear that they will capture a major share of the market currently held by natural gas based on fuel price alone.

Energy Consumption

As noted earlier, industrial energy consumption, as shown in Table 8-19, excludes certain types of industrial energy consumption: petroleum feedstocks, coking coal, and certain categories of petroleum fuel, and power consumption (liquefied gases, kerosene, gasoline, still gas, petroleum coke, and crude product). Industrial consumption as discussed in this

TABLE 8-19

INDUSTRIAL SECTOR ENERGY CONSUMPTION IN THE LOWER-48 STATES REFERENCE CASES 1 AND 2 (Quadrillion BTU)

	1990*	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Fuel & Power	(7.0)	(7.9)	(6.6)	(8.9)	(6.1)
Lease & Plant	(1.1)	(1.1)	(1.0)	(1.3)	(1.1)
Total Natural Gas	**8.1**	**9.0**	**7.5**	**10.2**	**7.2**
Electricity	3.2	3.7	3.6	4.5	4.3
Distillate Fuel Oil	1.2	1.1	1.0	1.2	1.0
High Sulfur	(0.3)	(0.3)	(0.5)	(0.2)	(0.3)
Low Sulfur	(0.3)	(0.6)	(0.6)	(0.4)	(0.4)
Total Residual Fuel Oil	**0.6**	**0.9**	**1.1**	**0.6**	**0.7**
Coal	1.7	1.9	1.6	2.2	1.5
Total	**14.7**	**16.6**	**14.8**	**18.6**	**14.6**

* Excludes petroleum consumed as feedstocks which represented an estimated 4.4 QBTU of consumption in 1990. It also excludes liquefied petroleum gases, kerosene, gasoline, still gas, petroleum coke, and crude product consumed for industrial fuel and power. These excluded petroleum products accounted for an 2.5 QBTU of industrial energy consumption in 1990.

section only refers to the subset of industrial fuel and power energy consumption shown in Table 8-19. The subset of industrial energy consumption included in this discussion accounts for about 65 percent of total industrial energy consumption.

The industrial sector is the largest *end-use* energy-consuming sector (i.e., residential, commercial, industrial, and transportation) in the United States. Among all energy-consuming sectors, only the electric power sector uses more energy. In 1990, the industrial sector accounted for 39 percent of total delivered energy consumption to the end-use sectors.

The industrial sector has a long history of steady improvement in energy conservation dating back to before the oil price spikes of the 1970s. However, the strong increase in industrial production between 1986 and 1989 appears to have slowed improvement in energy conservation significantly.

The slowdown and, in fact, reversal of the trend in energy conservation between 1986 and 1989 resulted from the increased use of existing production capacity. Capacity utilization increased from 79 percent in 1986 to over 84 percent in 1989. This involved the use of less efficient, older equipment. During the recession, this trend was reversed as the older, less efficient equipment was the first to be removed from service, much of it permanently. With recovery providing a spur to capital investment and reflecting improved efficiencies of production (due to recession-induced belt tightening), it is expected that the rates of industrial energy conservation will again begin to improve. In fact, continued energy efficiency improvement was made an explicit assumption in both Reference Cases.

Based on the subset of consumption included in Table 8-19, industrial energy consumption for fuel and power is dominated by natural gas in 1990. Natural gas accounts for 55 percent of consumption. Electricity accounts for 22 percent. Together, residual and distillate fuel oil account for just over 12 percent. Coal accounts for about the same share as residual and distillate fuel oil, almost 12 percent.

As shown in Table 8-19, total industrial fuel and power energy consumption is projected to grow at an annual rate of 1.2 percent in Reference Case 1. However, it is not projected to grow at all in Reference Case 2. Total energy consumption growth is significantly slower than assumed industrial production growth of 2.7 percent per year in Reference Case 1 and 2.25 percent per year in Reference Case 2. This implies significant improvement in energy intensity. In Reference Case 1, energy consumption per 1977 dollar of output is projected to fall from 7,355 BTU in 1990 to 5,468 BTU by 2010, or by 1.5 percent per year. In Reference Case 2 over the same period, energy intensity per dollar of output is projected to decline to 4,679 BTU by 2010, or at 2.3 percent per year.

The two Reference Cases present very different outlooks for industrial natural gas consumption. In Reference Case 1, natural gas consumption is projected to continue the growth experience since 1986 reaching 9.0 QBTU by 2000 and 10.2 QBTU by 2010. In this Case, gas consumption is projected to increase at 1.2 percent per year. In Reference Case 2, the increase implied in energy consumption by growth in industrial production is completely offset by improvement in energy intensity. The sharp decline in petroleum product prices discussed earlier, particularly residual fuel oil, worsens gas's competitive position and natural gas loses some market share to oil through 2000. Further, in this Case, electricity continues to make inroads in the industrial sector and gains market share from all fuels. The result of all of these factors is a net projected decline in natural gas consumption between 1990 and 2010 in Reference Case 2. Projected gas consumption falls from 8.1 QBTU in 1990 to only 7.2 QBTU by 2010, or a 0.6 percent decline per year.

Industrial electricity consumption is projected to continue to gradually increase in both Cases. Electricity consumption grows from 3.2 QBTU in 1990 to 4.5 QBTU in Reference Case 1 and 4.3 QBTU in Reference Case 2 by 2010. While natural gas faces price competition from residual fuel oil and distillate fuel oil in boiler applications, electricity provides strong competition in process heat applications. Further, electricity accounts for the dominant share of energy consumption for small motors for machine drive and, of course, lighting. The increased emphasis on the environment, particular in Reference Case 2, also provides an advantage to electricity. In some circumstances, the difficulty involved in the use of a fossil fuel because of emissions restrictions may make "ease of use" the most important criteria in energy selection. The choice of electricity over the fossil fuels completely eliminates the need for the industrial user to be concerned about emissions restrictions.

With the sharp decline projected in residual and distillate fuel oil prices between 1990 and 2000 in both Reference Cases, total petroleum consumption increases from 1.8 QBTU in 1990 to 2.0 QBTU in Reference Case 1 and 2.1 QBTU in Reference Case 2 by 2000. However, in the post-2000 period with increases in the petroleum product prices and stiffer emissions requirements, petroleum consumption is projected to decline from 2000 levels in both Cases. Total petroleum consumption falls to 1.8 QBTU in Reference Case 1 and 1.7 QBTU in Reference Case 2 by 2010. The entire decline in both Cases is in residual fuel oil consumption.

Coal has a BTU price advantage over all of the other fuels. In fact, this price advantage is projected to grow over the projection time frame. However, consumption of coal generally requires a larger capital investment than the other fuels and restrictions on emissions have a greater impact on coal than other fuels. Further, the potential for stricter emissions creates a degree of uncertainty or risk when consuming coal. Growth in coal consumption depends on strong production growth and continued relative low prices to offset the greater capital investment and risk associated with coal use. In Reference Case 1, industrial production is assumed to grow at 2.7 percent per year. The ratio of gas to coal prices is projected to increase from 1.6:1 in 1990 (natural gas versus high sulfur coal) to 3.1:1 by 2010. As a result, coal consumption is projected to increase from 1.7 QBTU in 1990 to 2.2 QBTU by 2010. With slower industrial production growth (2.25 percent per year) and lower gas and petroleum product prices (the ratio of gas to coal prices increases from 1.6:1 in 1990 to 2.7:1 by 2010), coal consumption declines to 1.5 QBTU by 2010 in Reference Case 2.

Natural Gas Consumption

Table 8-20 provides a detailed breakdown of total industrial fuel and power consumption of natural gas in the Reference Cases.

From 1986 to 1990, fuel and power consumption of natural gas grew sharply: by 10 percent in 1987, by over 5 percent in 1988, by 6 percent in 1989, and by an additional 6 percent in 1990. The growth in these years represented a change in direction from the trend that had been seen in the years before 1987. Industrial natural gas consumption for fuel and power had been falling steadily since the early 1970s before bottoming out in 1986 at roughly 6.1 QBTU.

There are four major components of industrial fuel and power consumption of natural gas in the industrial sector: boilers, non-boilers (process heat), cogeneration (including EOR), and lease and plant. Non-boiler consumption of natural gas represents the largest portion, over 40 percent in 1990. Consumption of gas in boilers accounts for about 35 percent, cogeneration accounts for over 9 percent, and lease and plant consumption of natural gas at drilling sites represents about 13 percent.

The most price-sensitive portion of the industrial fuel and power market is the boiler market. To maintain total industrial gas volumes, the natural gas share of the boiler market must be defended with technology advances and competitive pricing. In Reference Case 1 with competitive gas prices and relatively strong growth in industrial production, gas consumption in boilers is projected to increase from 2.8 QBTU in 1990 to 3.8 QBTU by 2010. However, in Reference Case 2 with relatively weak industrial production growth, strong efficiency improvement, and strong price competition from petroleum products, natural gas consumption declines to only 2.2 QBTU by 2010.

While listed separately in Table 8-20, the boiler market and cogeneration are directly related. In a cogeneration system, the production of steam is done in conjunction with the generation of power. The single best opportunity to increase the gas share in the boiler market is with cogeneration. Cogeneration technologies optimize the assets of gas in both steam and power applications and also serve a portion of the direct industrial electrical load. Consumption of gas in cogeneration is projected to grow from 0.7 QBTU in 1990 to 1.5 QBTU in Reference Case 1 and 1.4 QBTU in Reference Case 2 by 2010. Without the increased gas consumption for cogeneration, total gas consumption would grow significantly slower than shown in Table 8-20.

Currently, gas dominates the provision of non-boiler services (or process heat). In 1990

TABLE 8-20

INDUSTRIAL SECTOR NATURAL GAS CONSUMPTION IN THE LOWER-48 STATES BY APPLICATION REFERENCE CASES 1 AND 2 (Trillion BTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Boilers	2,831	3,114	2,391	3,783	2,224
Non-Boilers	3,467	3,501	2,943	3,637	2,411
Cogen/EOR*	748	1,253	1,217	1,488	1,447
Lease & Plant	1,061	1,135	997	1,253	1,068
Total	**8,107**	**9,003**	**7,548**	**10,161**	**7,150**

* Gas consumption for cogeneration is defined here as incremental consumption for power generation. It includes only the net increase in gas consumption directly due to the generation of electricity and excludes the portion of energy consumption attributable to the raising of steam. The portion of energy consumption attributable to the raising of steam is included under boilers.

gas was estimated to have almost 70 percent of all non-boiler services. In Reference Case 1, gas consumption for non-boiler services is projected to grow from 3.5 QBTU in 1990 to 3.6 QBTU in 2010. In Reference Case 2, however, gas consumption for non-boiler services is projected to fall to only 2.4 QBTU by 2010.

Much of the competition for non-boiler services is really an expected competition between gas and electricity. The high share of natural gas in non-boiler applications is an obvious target for increasing industrial electricity consumption. Natural gas competes with electricity in metal melting, smelting, metal heating, metal heat treating, drying, and certain types of glass manufacturing. The competition with coal is restricted to calcining and clay firing. Competition between gas and electricity (and in some select applications with coal) will increase in non-boiler applications, and gas technologies will have to keep pace with evolving industrial processes.

ELECTRIC POWER SECTOR

Much of the expectation about increased natural gas consumption in the future concerns the generation of electricity. As such, the major portion of the modeling work and analytical effort was directed at the projection of energy consumption for electricity generation.

The electric power sector is infinitely more complicated today than it was five or ten years ago. Today, electricity is generated, sold, and transmitted under a multitude of institutional arrangements. Potential electricity generators include utilities, cogenerators in the industrial and commercial sectors, independent power producers (IPPs), small power producers (SPPs), and utilities in Canada or Mexico that export power to the United States. The regulations each of these generators face, the cost of generation, the fuels and technologies selected, and the terms of sale vary significantly. Even the accounting for energy consumed for electricity generation is more complicated today. For example, the energy consumed for industrial and commercial cogeneration is usually included in the statistics for those sectors and the energy for IPPs is included in statistics for the industrial sector. The energy consumed for electricity generation by electric utilities, IPPs, and SPPs is accounted for in the electric generation sector. Finally, the energy consumed by foreign utilities for electricity that is exported to the U.S. is completely excluded from the U.S. primary energy balance.

This section only deals with energy consumed for electricity generated by electric utilities, IPPs, and SPPs; natural gas consumed by IPPs has been reclassified from the industrial sector and reclassified here. The energy consumed by industrial and commercial cogenerators is accounted for in those sectors. While the EEA model accounts for firm plans for new IPP and SPP generating capacity, the model does not make an explicit distinction in the forecast of new capacity decisions between electric utilities, IPPs, and SPPs. Therefore, potential biases in fuel mix, financing arrangements, and other factors are not accounted for. The implicit assumption is that the electricity will need to be generated by some entity and that the distinctions between electric utilities, IPPs, and SPPs will not significantly impact the selection of fuel or capacity type over the extended forecast.

In 1990, gas consumption by electric utilities, IPPs, and SPPs amounted to only 2.9 QBTU, just over 15 percent, of total lower-48 U.S. gas consumption. By 2010, this demand is projected to reach 5.4 QBTU in Reference Case 1 and 4.9 QBTU in Reference Case 2. However, the achievement of this growth is heavily dependent on the resolution of many issues concerning natural gas consumption for electricity generation. The forecast, itself, is heavily dependent on a set of assumptions made as part of the analysis. These assumptions are reviewed in the next section of this chapter.

Economic and Energy Assumptions

Table 8-21 summarizes the key economic and energy assumptions made for the electric power sector in the Reference Cases.

Purchased Electricity Growth

Energy demand to generate electricity is a derived demand. It is a function of the demand by the end-use sectors (residential, commercial, industrial, and transportation) for services such as space heating, space cooling, lighting, and machine drive. The mix of services met with electricity and the ability to use

TABLE 8-21

ELECTRIC POWER SECTOR ECONOMIC AND ENERGY ASSUMPTIONS

	Reference Case 1	Reference Case 2
Electricity Demand Growth	1.62% per year	1.30% per year
Repowering	Adds 21 GW To Existing Oil/Gas Capacity	Adds 15 GW To Existing Oil/Gas Capacity
Heat Rate Improvement	New Units Improve By 6% Over 1990 Technology	Same
	Existing Units Improve By 2-3% Due To Refurbishment	Same
Gas Transportation	New Gas-Fired Units Supplied Under Firm Transportation Rates	Same
	Existing Gas-Fired Units Supplied Under Interruptible Transportation Rates	Same
Price Expectations	Gas Prices Ramp Toward Residual Fuel Oil Price Equivalent	Same
Institutional Constraint On New Coal-Fired Capacity	Additional New Coal-Fired Capacity Constrained To Published Utility Plans through 2000, Full Economic Calculation Beginning In 2004	Same
Capital Costs	Consistent With New Grassroots Facility	Less Than Grassroots Facility, Assumes Construction At Existing Generating Site

other fuels to provide the service in place of electricity varies by sector. For example, there are no alternatives to electric lighting in any of the sectors. However, direct process heat services, which are specific to the industrial sector, can be provided by electricity or natural gas. The mix of services and the share of total electricity demand in each sector helps to determine the revenues and, in turn, the price of electricity.

The rate of purchased electricity growth in each of the end-use sectors was based on efficiency trends and fuel competition in each end-use sector and the targets for total electricity growth selected by the Task Group. The rate of growth in purchased electricity was not determined strictly by an economic competition in the model. In Reference Case 1, purchased electricity is assumed to grow at 1.62 percent per year. In Reference Case 2, aggregate purchased electricity by the end-use sectors is assumed to grow at a slower 1.3 percent per year. Both growth rates refer to demand, which is incremental to electricity provided by self generation.

The rate of growth in purchased electricity in Reference Case 1 was initially set equal to the rate of growth reported by the North American Electric Reliability Council (NERC), roughly 1.9 to 2.0 percent per year. However, the Task Group felt that DSM efforts by utilities would likely restrain electricity demand growth in the future to rates less than what is currently reported by the NERC. As a result, a lower, 1.62 percent per year rate of growth was adopted in Reference Case 1. The 1.3 percent per year rate of growth adopted in Reference Case 2 was set roughly proportional to the lower rate of economic growth (GNP) used in that Case.

The rate of growth in purchased electricity is not constant across the projection. The rate of growth tends to be lower in the earlier years of the projection and higher in the later years. This pattern represents a reversal of recent observed historical trends. The rate of growth in electricity demand has slowed steadily in each decade since the 1950s. In Reference Case 1, purchased electricity grows at 1.5 percent per year between 1990 and 2000 and at a faster 1.8 percent per year between 2000 and 2010. The same relationship holds in Reference Case 2. Between 1990 and 2000, purchased electricity is assumed to grow at 1.1 percent per year in this Case. Between 2000 and 2010, it grows at a faster 1.5 percent per year. This change in the growth trend reflects an assumption of strong near-term impacts from DSM programs, strong efficiency improvement in each of the end-use sectors, moderate growth in commercial square footage during the 1980s, and very rapid near-term growth in industrial cogeneration, which holds down purchased electricity growth.

The change in the growth rate trend is important in the selection of the fuel for new generating capacity. The economics of new natural gas-fired generating capacity are more favorable in the earlier years of the projection. However, the economics of new coal-fired generating capacity look better in the later years of the projection.

Repowering

Over 65 percent of the existing generating capacity in 1990 were steam units. Over 30 percent of these units, or over 20 percent of total U.S. generating capacity in 1990, were fired by either natural gas or petroleum. In many circumstances these units tend to be old and relatively inefficient. They offer the potential for repowering through the reworking of boilers, retrofit with waste heat boilers, or the addition of combustion turbines. In many situations repowering can by done at lower cost than building a completely new facility and the end result is a more efficient generating unit (though generally less efficient than a completely new unit) with a higher rated capacity. Furthermore, in some situations, updating an existing generating unit avoids siting issues and emissions per kwh generated are reduced.

Reference Case 1 assumes that about 25 percent of existing oil and gas-fired generating capacity is repowered (roughly 52 gigawatts) instead of retired. Through re-rating, this adds 21 gigawatts to total oil- and gas-fired capacity in this Case. In Reference Case 2 only about 35 gigawatts are assumed to be repowered. This adds 15 gigawatts to total oil and gas-fired capacity by 2010. The remaining oil- and gas-fired units are assumed to be refurbished rather than retired. Refurbishment is assumed to have no impact on the rated capacity.

Neither Reference Case includes an assumption of coal repowering. However, both Cases assume that the bulk of existing coal-fired generating capacity is refurbished and not retired. Only 3 percent of coal-fired capacity existing in 1990 is assumed to be retired between 1990 and 2010.

Heat Rate Improvement

The relationship between the generation of electricity and total energy demand for generation is generally straightforward. As more electricity is generated, the demand for energy input increases. However, the increase in energy demand for electricity generation is offset to some degree by improvements in generating capacity efficiency, which is measured by the generating capacity's heat rate. The heat rate is defined as the number of BTU required to produce one kilowatt-hour of electric energy.

In both Reference Cases, heat rate improvement for new and average generating capacity is measured by an index (1990 equals 100). The heat rate of new coal and gas/oil-fired generating capacity is assumed to improve by 6 percent by 2010; in both Cases, the index falls to 94. The stock average heat rate is determined as a weighted average of new and previously existing generating capacity. As a general rule, the stock average heat rate improves by about 4 percent by 2010 in both Cases. However, the stock average heat rate improvement in Reference Case 2 is somewhat slower than in Reference Case 1 because of the installation of less new capacity due to lower electricity demand growth.

Gas Transportation

The vast majority of the gas consumed for electricity generation today is purchased on spot markets and transported under interruptible contracts. However, while it varies by region, the average capacity utilization factor of existing gas-fired capacity is only about 20 percent. The projected growth in gas consumption for electricity generation is contingent upon the installation of significant quantities of new gas-fired capacity, primarily combined-cycle units, for use in intermediate and base load service. In this application, the capacity factor of the newly installed capacity will be significantly above the average of 20 percent today. Under this circumstance, the transportation of natural gas under interruptible contracts may not provide the service reliability required by the electric generator. As a result, for both Reference Cases the Task Group felt that the decision concerning new generating capacity should be based on gas prices using firm transportation rates. Existing capacity, however, is assumed to continue to run based on gas prices using interruptible rates. The assumption of firm transportation rates for new capacity decisions represents a conservative assumption in the analysis.

Price Expectations

The approach concerning price expectations was previously addressed in the General Assumption discussion on projection philosophy. In general, the decisions concerning the selection of new generating capacity is not based on perfect foresight. The Task Group decided to assume in both Reference Cases that decision makers assume that delivered natural gas prices move toward residual fuel oil prices in each region with some lag period (5 years) and then follow residual fuel oil prices over time. In the electric power sector this price expectation approach is complicated by the assumption of firm transportation rates for new generating capacity decisions. While the commodity price of natural gas is generally below residual fuel oil prices in all regions, with the additions of demand charges for firm transportation the delivered price may be above residual fuel oil prices in some regions in the initial year. In this Case, the delivered gas price is held constant in real terms until it is equal to the residual oil price. Once their prices are equal, the delivered gas price is assumed to track the residual fuel oil price.

Institutional Constraints on New Coal-Fired Capacity

The approach concerning institutional constraints on new coal-fired generating capacity was previously addressed in the General Assumption discussion on projection philosophy. In general, the Task Group felt that utilities faced an institutional constraint limiting the potential for the planning and construction of new coal-fired power plants in the near term. This constraint is assumed to persist until the late 1990s, when natural gas prices are clearly escalating (dispelling the perception that natural gas prices will remain near $2.00 per MCF forever), excess base load generating capacity has been worked off in most regions, utility financial problems have been resolved, and regulators, recognizing the need for new generating capacity, adopt attitudes that encourage utilities to install more capital intensive, coal-fired capacity.

To reflect this non-quantifiable, institutional constraint, the Task Group incorporated a constraint on the addition of new coal-fired generating capacity beyond those plants already planned. The Task Group established gas share floors that limited coal penetration in the near term. The model determination of new capacity was not based strictly on economics until 2004. Start-up of a plant in 2004 implies that a utility announces the plant and begins the process leading to construction between 1996 and 1999. This limitation was applied in both Reference Cases.

Capital Costs

In Reference Case 1, the capital costs for new gas- and coal-fired generating capacity in the base year (1990) were derived from the 1989 EPRI TAG report with some adjustments. The gas-fired capacity costs were increased from the TAG costs to reflect data concerning new plants currently coming on-line. The gas-fired combined-cycle unit is assumed to cost $700 (1990$) per kilowatt in 1990. The coal-fired unit capital costs were developed for two plant sizes, small (300 megawatt) and large (500 megawatt). In 1990 dollars, the small coal unit is assumed to cost $1,624 per kilowatt and the large unit $1,382 per kilowatt. The real capital costs for both the small and large coal and natural gas-fired capacity were escalated after 1990 at 1 percent per year. These capital costs are representative of the costs for a new green field facility. The costs for a new green field facility are used as the basis for the competition in Reference Case 1.

Due to the slower rate of capacity additions in Reference Case 2, a larger portion of the new coal-fired capacity will be built at existing generating sites. It is typically cheaper to add capacity at existing generating sites since many of the costs involved in a new green field facility can be avoided. For example, the costs involved with coal handling, site preparation, land acquisition, and water may all be either eliminated or shared. The Task Group, therefore, felt it was unreasonable to use the full green field cost for new coal units in Reference Case 2. From an examination of the detailed costs broken out in the EPRI TAG report, the Task Group determined that the new coal-fired capacity costs used in Reference Case 2 for the new capacity competition should be reduced by 23 percent for the large units and by 27 percent for the small units. The same assumption, however, was not implemented for natural gas.

Energy Prices

Table 8-22 compares the price of delivered energy by fuel type to the electric power sector in the Reference Cases. As was the case for the price of energy delivered to the industrial sector, the petroleum product prices shown in Table 8-22 for 1990 are artificially inflated by the events following Iraq's invasion of Kuwait. Natural gas prices, however, did not generally respond to the spike in petroleum product prices in 1990 but simply continued the gradual price erosion which began in the early 1980s. The projected rate of growth in delivered energy prices to the power sector between 1990 and 2010 in Reference Case 1 reflect these circumstances. As the gas bubble ends, natural gas prices are projected to increase at a relatively rapid 4.8 percent per year between 1990 and 2000, and petroleum product prices are projected to decline. Over the entire projection period, natural gas prices are projected to increase at 3.6 percent per year and residual and distillate fuel oil prices are both projected to increase at roughly 1.2 percent per year, with some variation by residual fuel oil sulfur category.

The relative projected rates of growth in delivered natural gas and petroleum product prices in Reference Case 2 reflect the same factors as Reference Case 1. However, the impact of starting from high petroleum product price levels in 1990 is exacerbated in this Case by the assumption of flat real crude oil prices between 1990 and 2010. Due to the lower projected level of demand, gas prices are also significantly lower in this Case. Between 1990 and 2010, natural gas prices are projected to increase at 2.4 percent per year. Residual and distillate fuel oil prices are both projected to decline over this period. Residual fuel oil prices decline by between 0.2 and 0.5 percent per year, depending on the sulfur category, and distillate fuel oil prices decline but only by a few cents.

Despite the faster projected growth in the price of natural gas, it remains competitive with both residual and distillate fuel oil through 2010 in both Reference Cases. Gas prices are projected to remain significantly below distillate fuel oil prices over the entire projection in both Cases and remain competitive with both 0.7 and 0.3 percent sulfur residual fuel oil. However, gas prices are not projected to remain below the price of 2.0 and 1.3 percent sulfur residual fuel oil over the entire projection period in both Cases. In Reference Case 1, natural gas prices are projected to be above 2.0 and 1.3 percent sulfur residual fuel oil by 2000. The price of natural gas is projected to, again, fall below that of 2.0 and 1.3 percent sulfur residual fuel oil by 2010. In Reference Case 2, which assumes no growth in real crude oil prices, natural gas prices remain above 2.0 and 1.3 percent sulfur residual fuel oil over the entire projection.

The BTU price of the fuel is not the only consideration in the selection of natural gas or petroleum for power generation, particularly not in the decision of what type of generating capacity to choose. With the enacted restrictions on SO2 emissions under the Clean Air Act Amendments of 1990, continued consumption of the higher sulfur grades of residual fuel oil

TABLE 8-22

ELECTRIC POWER SECTOR ENERGY PRICES IN THE LOWER-48 STATES REFERENCE CASES 1 AND 2 (1990$/MMBTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Natural Gas	2.10	3.37	2.74	4.23	3.37
Residual Fuel Oil					
2.0% Sulfur	3.27	3.06	2.37	4.27	2.95
1.3% Sulfur	3.44	3.20	2.51	4.41	3.09
0.7% Sulfur	3.62	3.47	2.75	4.63	3.35
0.3% Sulfur	3.87	3.80	3.10	4.96	3.69
Distillate Fuel Oil	5.09	4.90	4.17	6.48	5.08
Coal (Average)					
High Sulfur	1.40	1.30	1.23	1.27	1.20
Low Sulfur	1.52	1.69	1.55	1.74	1.61
Coal (New)					
High Sulfur	1.18	1.09	1.03	1.07	1.01
Low Sulfur	1.28	1.42	1.30	1.46	1.35

will be increasingly difficult and will involve significant expenditures beyond the cost of the fuel. Furthermore, residual fuel oil is not generally an option for technical reasons in much of the new, highly efficient generating equipment that is expected to be installed (e.g., combined-cycle and turbine units). Therefore, the future consumption of residual fuel oil will largely be restricted to the existing, less efficient steam units. As these steam units are repowered or retired, residual fuel oil consumption will fall in the future.

The major competition for natural gas for new generating capacity will be coal. However, the evaluation of this competition and the direction it will take has been made difficult by the fact that the average delivered price of coal in both nominal and real dollars has been dropping steadily since the mid 1980s. The reasons for this decline have been the continued existence of surplus coal supplies, rapid improvements in coal mine productivity, and relatively flat transportation charges. The decline in the average price is driven by the "rollover" or renegotiation of old, long-term contracts and from increased spot purchases of coal by electric generators. The relative economics of coal versus other fuels in the selection of new generating capacity is not based on the weighted average U.S. price of coal but on the new contract price of coal which is significantly lower than the average.

This distinction was accounted for in the model in both Reference Cases. The economics of the continued operation of existing coal-fired plants were based on the weighted average U.S. coal price, but the decision to build a new coal-fired power plant was based on the new contract price of coal. The new contract price of coal was, on average, about 16 percent lower than the average U.S. coal price in 1991. The analysis assumes that this 16 percent difference remains constant over the entire projection. This is a conservative assumption. It would be reasonable to assume that this differential would narrow over time. Table 8-22 shows both the average and new contract coal price used in the economics of new capacity decisions.

In both Reference Cases, gas's competitiveness relative to coal declines over the projection. In Reference Case 1, both the projected average and new contract high sulfur coal prices decline by 0.5 percent per year between 1990 and 2010. Over the same period, the average and new contract low sulfur coal prices increase at only 0.7 percent per year. In Reference Case 2, the average and new contract high sulfur coal prices are projected to decline at 0.8 percent per year between 1990 and 2010. The average and new contract low sulfur coal prices are projected to increase at only 0.3 percent per year over this period. Over the same period, natural gas prices are projected to increase by 3.6 percent per year in Reference Case 1 and by 2.4 percent per year in Reference Case 2.

As has been the case throughout this analysis, a comparison of strictly the BTU delivered price of various fuels may not be a good relative measure of competitiveness. Other non-price considerations, which may impact the users' absolute ability to use the fuel or the capital investment required, need to be considered as well. For example, the capital investment required to use coal is significantly greater than that for natural gas, the existing emissions regulations are more stringent on coal than on natural gas and the potential exists for strong new regulations, the siting of new coal generating capacity tends to be more difficult, and the construction lead-time longer. All of these factors lead to greater risk when using coal.

Energy Consumption

Energy consumption for electricity generation shown in Table 8-23 includes energy consumed by electric utilities and IPPs. The energy consumed by industrial and commercial cogenerators is accounted for in those sectors.

In 1960, total energy consumption for electricity generation accounted for about 19 percent of total U.S. primary energy consumption. By 1990, excluding the energy consumed by cogenerators, it accounted for over 36 percent of total U.S. primary energy consumption. The projection shows this trend continuing, but at a more modest pace. Based on the subset of total primary energy consumption included in the projection, energy consumption for power generation (excluding cogeneration) will grow from representing 58 percent of the subset of total primary energy consumption in 1990 to 60 percent in 2010 in Reference Case 1 and 63 percent in Reference Case 2. Total electric power energy consumption is projected to grow from 29.4 QBTU in 1990 to 37.7 QBTU in Reference Case 1 and 35.5 QBTU in Reference Case 2 by 2010.

In 1990, electric power sector energy consumption was dominated by coal, which accounted for 55 percent of total consumption.

TABLE 8-23

ELECTRIC POWER SECTOR ENERGY CONSUMPTION IN THE LOWER-48 STATES REFERENCE CASES 1 AND 2 (Quadrillion BTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Natural Gas	2.9	3.9	3.2	5.4	4.9
High Sulfur	(0.5)	(0.5)	(0.5)	(0.4)	(0.4)
Low Sulfur	(0.7)	(0.6)	(0.8)	(0.7)	(0.6)
Total Residual Fuel Oil	**1.2**	**1.1**	**1.3**	**1.1**	**1.0**
Distillate	0.1	0.2	0.1	0.2	0.2
Coal	16.1	17.2	16.8	20.9	19.3
Nuclear/Hydro/Other	9.2	10.4	10.3	10.2	10.1
Total	**29.4**	**32.7**	**31.8**	**37.7**	**35.5**

Nuclear/hydro/other accounted for 31 percent of consumption. Together, residual and distillate fuel oil accounted for just over 4 percent and natural gas 9.8 percent of total consumption. The gas share of energy consumption for electric power generation has declined sharply over the last 20 years. As recently as 1971, natural gas accounted for 24 percent of the energy consumed for electric power generation.

The growth in total energy consumption for electric power generation does not occur at a constant rate over the projection. As a result of the relatively slower assumed growth in purchased electricity consumption between 1990 and 2000, total consumption in Reference Case 1 is projected to grow at 1.1 percent per year during this period. After 2000, total consumption grows at a faster 1.4 percent per year. The same pattern of growth is seen in Reference Case 2. Total energy consumption is projected to grow by 0.8 percent per year between 1990 and 2000 and a faster 1.1 percent per year between 2000 and 2010.

In the period from 1990 to 2000, new capacity additions are largely constrained to reflect the published announcements of electric utilities. However, the model has the ability to delay or drop an announced new generating facility if the projection implies that the power will not actually be needed at the published on-line date. The model implicitly anticipates the revision of the plant on-line date published by the NERC. Historically, these data have been extensively revised from year to year. Thus, this approach is consistent with experience. However, for purposes of this analysis, the planned coal-fired generating capacity that is actually under construction (not merely planned) was forced on-line irrespective of the need at a given time. This was done as a conservative assumption and has the effect of lowering the amount of new natural gas-fired capacity added during the 1990s.

In Reference Case 1, natural gas consumption is projected to grow from 2.9 QBTU in 1990 to 3.9 QBTU by 2000. This growth largely reflects published the NERC plans for new gas-fired capacity. As shown in Table 8-24, gas captures the largest share of new generating capacity between 1990 and 2000 (over 38 percent). The assumed institutional constraint on new coal-fired capacity also helps to increase the gas share of new capacity during the 1990s.

In the post-2000 period, gas consumption in Reference Case 1 is projected to grow from 3.9 QBTU in 2000 to 5.4 QBTU by 2010. As shown in Table 8-24, significantly more new capacity is added after 2000. While the gas share of new capacity is slightly lower (down to 37.3 percent), the total amount of new gas capacity added is actually higher (66,746 megawatts versus 30,128 megawatts). Further, capacity utilization rates are higher in the post-2000 period as reserve margins tighten. Both of these factors contribute to a faster increase in gas consumption.

In Reference Case 2, gas consumption is projected to grow from 2.9 QBTU in 1990 to only 3.2 QBTU by 2000, or at 1.0 percent per year. The low growth rate in purchased electricity consumption holds down the need for increases in gas-fired capacity and generation. The result is very little growth in projected gas consumption in Reference Case 2 before 2000. In the period between 2000 and 2010, gas consumption for electric power generation is projected to grow at a fast 4.4 percent per year, from 3.2 QBTU in 2000 to 4.9 QBTU by 2010. The dynamics of this growth are very different than in Reference Case 1. First, purchased electricity consumption is assumed to grow faster in this later period. This leads to an increased need for new generating capacity. Second, gas prices are significantly lower in this Case, both absolutely and relative to coal. As a result, gas captures a higher share of new capacity built between 2000 and 2010 in Reference Case 2 than in Reference Case 1. Last, since less new capacity is added in this Case over the entire projection, the heat rate improvement is less than in Reference Case 1. As capacity utilization is increased, the higher heat rate translates into more natural gas consumption.

Total petroleum consumption changes very little over the projection in either of the Reference Cases. It remains at roughly 1.3 QBTU over the projection in both Cases. There is a very small decline in high sulfur residual fuel oil consumption which is offset by a small increase in distillate fuel oil consumption. The potential for growth in petroleum consumption is handicapped by the SO_2 emission restrictions as well as relatively high prices. Further, residual fuel oil is generally not an option in

TABLE 8-24

FUEL SHARES OF ELECTRIC UTILITY BASE AND INTERMEDIATE LOAD CUMULATIVE GENERATING CAPACITY ADDITIONS REFERENCE CASES 1 AND 2 (Percent)

	1990-2000		2000-2010	
	Case 1	Case 2	Case 1	Case 2
Oil/Gas Steam	3.5	3.8	6.1	5.6
Oil/Gas Combined-Cycle	34.6	28.9	31.2	38.2
Coal Steam	32.4	30.7	57.5	50.3
Hydro/Other	7.2	6.1	5.2	5.0
Nuclear	22.2	30.5	0.0	0.0
Total Additions (Megawatts)	41,702	30,387	119,995	91,266
Peak Capacity Additions (Megawatts)	14,240	10,881	21,988	16,927

much of new combined-cycle generating capacity constructed over the projection in both Cases. While distillate fuel oil can be used in combined-cycle units, the price of distillate fuel oil is higher than natural gas over the entire projection so there are few opportunities for its use. Distillate fuel oil will only be used when natural gas is not available, on a seasonal basis, or where regulations implicitly require its use (for example, requirements to maintain a back-up fuel on site which needs to be used within a given time interval to avoid degradation of fuel quality).

Coal consumption is projected to grow significantly in both Reference Cases. Coal consumption is projected to grow from 16.1 QBTU in 1990 to 20.9 QBTU in Reference Case 1 and to 19.3 QBTU in Reference Case 2 by 2010. However, the projected growth in coal consumption between 1990 and 2000 is very modest in both Cases. A very limited amount of new coal-fired capacity is added over this earlier period, only 13,500 megawatts in Reference Case 1 and 9,300 megawatts in Reference Case 2. Second, the little remaining nuclear capacity under construction comes on-line over this period. This new nuclear capacity tends to compete directly with coal for base load generation and backs out coal generation in the short term. Last, in the period before the year 2000, the levelized economics of new gas-fired generating units are competitive if not better than new coal-fired facilities in many regions. This favors natural gas use in the period before 2000.

In the period from 2000 to 2010 coal grows substantially in both Cases. In Reference Case 1, coal consumption is projected to grow from 17.2 QBTU in 2000 to 20.9 QBTU by 2010. In Reference Case 2, it is projected to grow from 16.8 QBTU in 2000 to 19.3 QBTU by 2010. This growth results from two basic factors. First, coal is no longer being backed out by new nuclear plants. Second, steady increases in gas prices over the projection with little projected increase in coal prices have changed the relative economics of coal versus natural gas. In the post-2000 period, the levelized cost of a new coal-fired power plant tends to be less than that of a new gas-fired generating plant in most regions. As shown in Table 8-24, the coal share of new generating capacity is projected to increase sharply in the post-2000 period in both Cases. Coal is projected to capture over 57 percent of new intermediate and base load capacity between 2000 and 2010 in Reference Case 1 and 50 percent in Reference Case 2.

Aside from the completion of the nuclear generating units that remain under construction between 1990 and 2000, consumption of nuclear/hydro/other shows little growth in either Case. Nuclear/hydro/other grows from 9.2 QBTU in 1990 to just over 10 QBTU in both Reference Cases by 2010. There is very little new hydro or other (renewables, waste, etc.) generating capacity currently planned by utilities despite the statements concerning its potential.

Natural Gas Consumption

Table 8-25 provides a detailed breakdown of total electric power sector natural gas consumption in the Reference Cases.

The outlook for natural gas consumption for electricity generation is increasingly being presented as more optimistic in most contemporary projections. Part of this optimism is due to changes in published utility plans over the last few years concerning the construction of new gas-fired generating capacity. In 1986 DOE/EIA data, utilities were listed as planning to add 40 new gas-fired plants with a capacity of 3,000 megawatts between 1987 and 1996. In 1990 DOE/EIA data, utilities are now listed as planning to build 203 new gas-fired plants with a capacity of 18,475 megawatts by 2000. This change indicates a revised interest in adding new gas-fired capacity.

Many of the new gas-fired plants currently listed in the data are intended for peaking applications. However, the DOE/EIA data indicate that the average size of the new units is increasing over time. In 1986, the 40 new gas-fired units planned by utilities had an average size of 75 megawatts. By contrast, the average size of the new gas-fired units on order in 1990 was 90 megawatts. From 1991 to 1995, the range in the average size of gas-fired units is 66 to 88 megawatts. From 1996 to 2000, the range in the size of the units increases to 91 to 122 megawatts. The relatively larger average size of the units on order in 1990 implies that many of these units will be used in intermediate load service. While the initial orders were largely for peaking applications, a growing number of the more recently ordered units appear to be for non-peaking service. This implies a higher level of capacity utilization and greater levels of gas consumption.

Both Reference Cases reflect this optimism about the potential for increased gas consumption for electricity generation. Gas demand for electricity generation is projected to grow significantly over the projection period as new capacity comes on-line and as utilization of existing capacity increases. Consumption is projected to increase from 2.9 QBTU in 1990 to 5.4 QBTU in Reference Case 1 and 4.9 QBTU in Reference Case 2 by 2010.

Table 8-25 shows gas consumption for power generation broken down by prime mover or application: steam, turbine, combined-cycle, and co-firing/reburn. Gas for steam generation accounted for the major portion of total consumption in 1990, over 80 percent. Turbines (largely in peaking applications) accounted for the second largest portion of gas consumption, about 12 percent. Gas consumption in combined-cycle generating units represented a relatively small 6 percent of total gas consumption in 1990. Little or no gas is consumed for emission control through co-firing/reburn in 1990. This application represents a potential mode of consumption.

TABLE 8-25

ELECTRIC POWER SECTOR GAS CONSUMPTION IN THE LOWER-48 STATES BY CAPACITY TYPE REFERENCE CASES 1 AND 2 (Trillion BTU)

	1990	2000		2010	
		Case 1	Case 2	Case 1	Case 2
Steam	2,328	2,553	2,150	2,797	2,673
Turbine	356	464	435	640	577
Combined-Cycle	168	621	418	1,726	1,498
Co-firing/Reburn	0	229	229	189	189
Total	**2,852**	**3,866**	**3,232**	**5,352**	**4,936**

Gas consumption for steam generation is projected to remain the dominant form of generation with gas over the projection. Steam generating capacity is used for peak (as spinning reserve), intermediate, and base load service. In 1990, the capacity of steam generating units that can use gas alone, in dual, or triple fueled units was 146.8 gigawatts. Between 1990 and 2010, only 96.8 gigawatts, including all types of gas-fired generating units (turbines, steam, and combined-cycle), are projected to be added. Little of the new capacity is steam. The majority is either turbines for peaking or combined-cycle units. However, the large amount of existing steam capacity today will alone guarantee that this remains the most important contributor to total gas consumption for power generation. As a result, gas consumption for steam generation grows from 2.3 QBTU in 1990 to 2.8 QBTU in Reference Case 1 and 2.7 QBTU in Reference Case 2 by 2010. Much of this increase is due to the increased utilization of existing capacity as reserve margins tighten. By 2010, steam generation that accounted for 80 percent of gas consumption in 1990 accounts for 52 percent of consumption in Reference Case 1 and 54 percent in Reference Case 2.

Today, gas consumption in turbines is largely attributable to peaking load. While most of the consumption in the future is projected to still be for peaking service, the projection also reflects the increased use of turbines for intermediate load. In both Reference Cases, gas consumption by turbines is projected to grow rapidly, at almost 3.0 percent per year in Reference Case 1 and by 2.4 percent per year in Reference Case 2. Total gas consumption in turbines is projected to grow from less than 0.4 QBTU in 1990 to over 0.6 QBTU in Reference Case 1 and just under 0.6 QBTU in Reference Case 2 by 2010.

Gas consumption in combined-cycle generating units represents a small amount of total gas consumption in 1990 only about 0.2 QBTU. However, because of improving efficiencies, short construction lead-time, and low capital costs, gas-fired combined-cycle capacity is projected to account for most of the growth in power sector gas consumption over the projection. In Reference Case 1, combined-cycle gas consumption is projected to grow from 0.2 QBTU in 1990 to 1.7 QBTU by 2010. In Reference Case 2, gas consumption in combined-cycle units reaches 1.5 QBTU by 2010. Gas-fired combined-cycle generation, which accounts for only 6 percent of total gas consumption in 1990, is projected to account for a much larger 32 percent in Reference Case 1 and 30 percent in Reference Case 2 by 2010. This growth depends entirely on the installation of a large quantity of new generating capacity, not just the increased utilization of existing capacity. Without the installation of these new combined-cycle units, gas consumption by 2010 would only be 3.8 QBTU in Reference Case 1 and 3.6 QBTU in Reference Case 2. This highlights the importance of resolving any obstacles to increased gas consumption for electricity generation to the gas industry.

A key provision of Title IV of the Clean Air Act Amendments of 1990 concerning acid rain was the mandated reduction of 10 million tons of SO2 from fossil-fueled steam generators by 2000. This was to be done in two phases. In Phase 1, steam generators would need to meet a target of 2.5 pounds per MMBTU by 1995 or 1996. Under Phase 2 generators need to meet an emission standard or 1.2 pounds per MMBTU by 2000 or 2001. The potential control options include scrubbing, coal switching, the use of clean coal technologies, co-firing or reburn with natural gas, the purchase of emissions allowances, or trading. The potential strategies involved with meeting the Phase 1 and 2 standards were evaluated as part of the analysis. While the results suggest that coal switching, the purchase of allowances, or trading is likely to be the most widely used strategy, it is likely that some gas will used for emission control. In both Reference Cases, the analysis suggests that about 0.2 QBTU of gas will be consumed in 2000 and 2010 for emission control under Phase 1 and 2 of Title IV.

CONCLUSIONS

Natural Gas Has Potential to Grow

The projection confirmed that natural gas has the potential to grow in the future, particularly in the electric power generation and industrial sectors. The potential for growth in the electric power generation sector is, however, dependent on the successful resolution of a large number of issues. Further, gas consumption growth in this sector is dependent on continued growth in purchased electric power. If DSM, IRP, and mandated efficiency programs are successful, or more successful than currently anticipated, the markets for gas-fired generation of electric power may simply not develop. The analysis confirmed that the greatest potential for increased gas consumption for power generation (based on the levelized cost of a kwh generated with natural gas over the life of the generating facility) is during the 1990s. The levelized cost of electric generation favor natural gas over a wide range of situations during the 1990s. In the post-2000 period, with projected increases in gas prices, natural gas loses its economic advantage in many areas of the country.

The potential for increased industrial natural gas consumption is large but much more uncertain. The wide projected range in industrial gas consumption from 10.2 QBTU in Reference Case 1 to only 7.2 QBTU (a level lower than consumption today) in Reference Case 2 clearly illustrates this uncertainty. Unfortunately, most of the factors driving this uncertainty are largely beyond the control of the natural gas industry. These factors include growth in industrial production, trends in the mix of industry, and improvement in energy intensity.

Potential Growth Markets are Largely Price Sensitive

While price is not the only factor impacting energy markets, it is an important factor in the markets that hold the greatest potential for increased natural gas consumption. Currently, both the industrial and electric power generation sectors are largely driven by simply the commodity price of natural gas versus other fuels. However, this emphasis could change in the future as emissions restrictions are toughened. The gas industry needs to recognize the growing importance of non-price factors and adjust its marketing approach to target directly to these issues. This does not mean, however, that gas will be priced at a premium in end-use markets.

Other Markets Besides the Industrial and Electric Power Sectors are Important and Need To Be Defended

The markets that are not driven by commodity price alone, the residential and commercial sectors, are expected to continue to be important markets for natural gas in the foreseeable future. Residential and commercial consumption of natural gas accounted for over 38 percent of total consumption in 1990. By 2010, despite substantial growth in the electric power and industrial sectors, these two markets will still account for between 34 and 38 percent of total natural gas consumption. Some of these more traditional applications represent high value uses, because the competition is with more costly alternatives such as electricity and high grade distillate fuel oil.

Space conditioning in the residential and commercial sectors is an important example. This consumption of natural gas is often erroneously referred to as a captive market. However, viable alternatives to gas space conditioning are available to each customer. It is true that once an investment in heating or cooling equipment has been made by a residential or commercial customer, that customer is unlikely to replace the equipment prematurely because of moderate fuel price fluctuations. Nevertheless, thousands of new investments are being made each year based upon contemporary fuel prices and the available equipment options. Over a ten-year period, 40 percent of the total gas space conditioning load will be subject to new user choices. If the commodity price is noncompetitive, or if the available gas equipment should fail to meet future policy standards and consumer preferences, this high value market share could rapidly erode.

Potential Variation in Future Energy and Natural Gas Consumption is Very Large

The analysis clearly establishes that depending on the direction a few important variables take (e.g., economic growth, the mix of industrial production, improvement in energy intensity, technology, etc.), the level and mix of total energy consumption and the role that natural gas plays can vary substantially. This illustrates the importance of contingency planning when corporate or personal decisions are based on projections of future energy trends. It also highlights the high level of uncertainty associated with energy projections.

Energy Prices Matter, But So Do Other Factors

Energy analysts tend to place a great deal of emphasis on energy prices. They explicitly, or at least implicitly, assume that if the price of a fuel rises (falls) relative to other fuels that consumption will fall (rise). However, the analysis shows that while price is important, it is not the only important factor and may not even be the most important factor. Equally important, to name a few, are trends in energy intensity, economic growth, a decision maker's expectation about future energy prices, institutional constraints, and technology trends. This highlights the need to pay increased attention to these variables in place of simply the direction of price.

Technology is Important

In every sector, the trend in technology was important to the success or failure of natural gas in competition with other fuels. Improved natural gas technologies contribute by maintaining current gas market share in the face of improved competitive technologies; in meeting new standards for emissions, product quality, or consumer needs; and in expanding the gas market by offering new services. The analysis showed that gas technology improvement was a key consideration in each sector.

The characteristics and capabilities of the available gas technologies will be the factor deciding the choice of fuels as often as the fuel price in future markets. The future market share for gas in industrial markets will be largely decided by the characteristics of the available technologies as they can conform to environmental and energy efficiency policies. Vehicle applications and the incremental growth in electric power generation are equally dependent upon technological advances. The characteristics of gas turbines and methane vehicle technologies will have to be improved to keep pace with future emission standards. The operation of numerous large turbine power plants in conjunction with normal pipeline system services may involve technical problems yet to be resolved. Similarly, vehicle engine, fuel storage, and refueling technologies need much more development. If the optimistic outlook for these new applications is to be realized over the long term, the advanced technologies must become available.

APPENDICES

The Secretary of Energy
Washington, DC 20585

June 25, 1990

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

Dear ~~Mr. Cook~~ Lod:

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

<u>Constraints to Expanding Natural Gas Production, Distribution and Use</u>

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.

<u>The U.S. Refinery Sector in the 1990's</u>

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

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

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

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

Sincerely,

Jim

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

Description of the National Petroleum Council

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

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

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

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

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

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

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

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Region	States
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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

APPENDIX C
INTEGRATED RESOURCE PLANNING

INTRODUCTION

Integrated Resource Planning (IRP) has been under development and implementation in the electric utility industry for some time and has gained acceptance within the gas utility industry in recent years.[1] This effort is projected to expand, and the implementation of IRP is expected to increase trends towards energy conservation and economic efficiency. The implementation of IRP varies from state to state, but the basic concept is that when a utility plans its future resource requirements to achieve a balance between supply and demand, it must:

- Consider demand reductions as well as supply increases on an equal basis
- Evaluate all demand-side and supply-side alternatives on an equal basis
- Evaluate programs and options for economic efficiency
- Select alternatives based upon lowest cost to customers
- In some states factor in environmental externalities.

The following terms and concepts appear in discussions of IRP:

1. ***Demand-Side Activities***: These include load management with the objective to reduce peak demand, as measured in kilowatts or Therms, or to shift peak demand to off-peak periods. The reduction of peak demand reduces the need to build or buy new generating capacity in the case of electric utilities, or to add transmission or storage capacity in the case of gas utilities.
2. ***Conservation***: The objective is to reduce the amount of energy used. Conservation results in reduced fuel use and reduced or avoided environmental impacts.
3. ***Supply-Side Activities***: These include actions to increase the ability to obtain energy. In the case of an electric utility this includes production, transmission, and distribution of electricity. In the case of a gas utility this refers to the extraction, transmission, storage, or distribution of gas.
4. ***Environmental Externalities***: This refers to an environmental cost borne by society that is not immediately reflected in the price paid by the producer or consumer.
5. ***Rate Payer Tests***: These measure economic efficiency. Examples of such tests include the All Ratepayers (Total Resource Cost), Non-Participants (Rate Impact Measurement), Participants, Utility, and Societal tests.
6. ***Economic Efficiency***: As defined by economists, marginal revenue, price, and marginal cost achieve equality. This results in Pareto Optimality. From a practical viewpoint this means that correct pricing

[1] IRP is also sometimes denoted as Least Cost Planning (LCP); the former term appears to be somewhat more descriptive.

signals (generally based on marginal cost) are sent to the consumer.

IRP involves a new approach to the delivery and pricing of utility services. Prior to IRP, electric and gas utilities primarily viewed themselves as providers of electricity and natural gas; following the implementation of IRP, the utilities are much more heavily involved in the customers' fuel decisions—including equipment, fuel utilization, and fuel choice. IRP is gaining increasing momentum in its application. A recent survey by the Electric Power Research Institute (EPRI)[2] showed that:

- 31 states have some sort of electric IRP in place
- 10 additional states have electric IRPs under study
- 14 states have examined and implemented externality requirements
- 7 additional states have requirements under development.

In the case of natural gas, a recent survey[3] categorized states by their activity in IRP for natural gas distribution utilities. The categories are:

- In Practice—Utilities have submitted IRP Plans.
- In Implementation—Utilities are subject to regulatory enforcement mechanisms to submit IRP Plans.
- Under Development—Active consideration of least cost planning issues with the intention of filing IRP Plans.
- Under Consideration—Discussions concerning least cost planning issues are taking place at the Commission or legislative level.
- Not Actively Considered—Development of IRP Plans is not imminent.
- Rejected—Commissions have formally rejected LCP requirements for natural gas utilities.

[2] Electric Power Research Institute (EPRI) 1988. "Status of Least-Cost Planning in the United States," EPRI EM-6133, Palo Alto, CA, December.

[3] Applied Science Division, Lawrence Berkeley Laboratory, Survey of State Regulatory Activities on Least Cost Planning for Gas Utilities, April, 1991.

The survey found that 15 jurisdictions either had gas IRPs implemented or in practice (the District of Columbia, Illinois, Iowa, Nevada, New Jersey, Oregon, Vermont, Washington, and Wisconsin) or under development (California, Connecticut, Hawaii, Massachusetts, New York, and Rhode Island). Seven states were found to have gas IRPs under consideration (Alabama, Colorado, Maryland, Michigan, Montana, New Hampshire, and Ohio). Of the 29 states that are not actively considering IRP for natural gas distribution utilities, two states (Nebraska and Texas) do not regulate natural gas distribution at the state level and nine states (Arizona, Delaware, Georgia, Kansas, Kentucky, Missouri, Pennsylvania, Utah, and Virginia) are analyzing the experience with an electric IRP process before going forward with an application of IRP principles on the natural gas side.

These results seem to indicate a great degree of interest in IRP for natural gas distribution utilities themselves as well as a large potential for even greater interest as the results of the electric utility experience with IRP become available. This will have a large and direct effect on the demand for natural gas.

ORIGIN OF IRP

Integrated Resource Planning activities were initiated in the electric utility industry because many electric utilities were faced with significant needs for the expansion of their systems to meet rising demands for electricity. State regulators began to examine whether the increased need for electricity could be met with greater economic efficiency through conservation alternatives promoted by the utilities instead of the additional production of electricity. The expansion requirements facing many electric utilities were, to a significant degree, caused by incorrect pricing signals communicated via the rate structures to the consumer. The rate structures communicated a price for a kilowatt hour (kwh) to the consumer that was significantly less than the marginal cost of that additional kwh. Therefore, the consumer demanded more electricity than was economic to produce, resulting in economic inefficiency.

The drivers of marginal cost for an electric utility are the factors that contribute to generation, transmission, and distribution expenditures. Until the early 1970s the marginal cost of electricity was declining for most major electric utilities; since that time it has generally been in an increasing mode. That is, additional production of electricity costs more than the average cost of the total electricity produced. However, utility rates are generally set on the basis of average cost. Therefore, electric utilities were selling electricity at the margin for less than it cost to produce. An example would be a peak hour on a summer peaking system with electricity costing possibly 20 cents to produce but selling for possibly 10 cents on an average cost-of-service basis. There has been general agreement that under such a scenario the pricing system does not communicate accurately to the consumer the true economic costs of consumption. This results in over consumption in lieu of conservation.

CONCEPTS OF IRP

The efficient pricing of products at their marginal cost results in economic efficiency. This type of outcome theoretically occurs in a non-regulated competitive market. Since utilities are regulated and since pricing is on the basis of average cost, the consumer generally does not respond to the marginal cost implications. In the case of rising marginal cost, the consumer will perceive that the true cost of electricity is less than it actually is, and the consumer will demand more electricity than is economically efficient. The consumer will undervalue conservation. Accordingly, the implementation of IRP attempts to create an environment in which costs of supply for a utility service and costs of demand for a utility service are correctly considered, and in which market imperfections that prevent the attainment of economic efficiency are minimized.

The major problem that resulted in the development of IRP was that the underpricing of electricity at the margin resulted in the over expansion of supply; that is, electric utilities were spending too much on investment in new plants and equipment, and the consumer was spending too little on conservation. Utilities have traditionally focused their investments on the supply-side: i.e., those activities necessary to assure the delivery of their product to the consumer in the most efficient manner. IRP can arrive at an improved allocation of resources by forcing the simultaneous consideration of all supply options and costs, and all demand options and costs. IRP has as its basic premise, planning to assure that all sources—e.g., conservation as well as supply—receive adequate consideration. Utilities are being required to be more involved in demand-side planning since consumers have under-invested in demand-side options available at this time. Consumers have avoided making demand-side investments due to their perception of a lower investment return on those resources. As a result of customers' discount rates being so high, relative to those of a utility, demand-side options are available for the utility to pursue as an investment strategy to reduce costs. Utility demand-side investment focuses on making the appropriate level of investment to achieve economic efficiency.

IRP is now being undertaken within the gas industry. Many gas utilities face different economic structures from those faced by an electric utility. Marginal costs are not necessarily increasing; in fact for many LDCs marginal costs are constant or declining. IRP has some strong implications for the gas business:

- IRP programs for gas utilities will result in less consumption per customer, and—other things being equal—a lower level of throughput by the LDC. By increasing the value of natural gas to the consumer via Demand Side Management, LDCs are able to retain existing load, more effectively market gas as an obvious value to new customers, and delay or reduce the need to build new facilities.
- IRP that considers interfuel selection generally leads to the conclusion that conversion of some end uses from alternate fuels to natural gas is an economically efficient, lower cost option. For example, a good case can be made that there are significant benefits from the new, high efficiency double-effect absorption commercial air conditioners, which have a lower operating cost than electric air conditioners and whose installation helps to avoid the additional construction of power plants.

CONTENTS OF A TYPICAL IRP PLAN

IRPs are very similar for both gas and electric utilities; they typically have:

- Supply Scenarios, based on marginal cost and fuel procurement models of distribution facilities and gas purchasing options
- Demand Scenarios, usually based on end-use models of residential, commercial, multifamily, industrial, and other types of demands
- Cost Effectiveness Tests, which measure the benefits of demand-side programs, including such tests as a participants test, a non-participants test, an all ratepayers test, a utility cost test, and other tests as appropriate
- Program selection and integration techniques, to provide for appropriate analysis and feedback effects
- Evaluation techniques focusing on economic efficiency
- Plan Integration.

These can be discussed in greater detail.

Supply Scenarios

Supply scenarios are long-term forecasts of the various supply options available to the utility to meet various levels of demand, including a derivation of the least cost supply strategy. These optimization programs are computer driven and include as examples, OGP type models for electric utilities and ROGM type models for gas utilities.[4] Electric utilities, by the nature of their capital investment requirements have focused their supply planning on periods of 15 or more years. Gas utilities, without the same capital investment requirements, traditionally forecast for five years. IRP will require longer term forecasting from gas utilities in order to better match the long-term benefits from demand-side programs, such as a higher efficiency residential boiler, to the avoided supply costs. An IRP will generally include a number of supply scenarios.

Demand Scenarios

Demand scenarios are long-term forecasts of the demand for each segment of a utility's customer base. Traditional forecasts have identified consumption by utility rate classes, which included multiple end uses. Current forecasts are now utilizing more of an end-use framework to better match the end uses for a particular fuel with the demand-side programs that can impart a change in demand for the end use. Models typically include residential, commercial, apartment, industrial, and other sectors. Disaggregation is based on space conditioning, water heating, lighting, process use, and other end uses.

Cost Effectiveness Tests

Demand-side investments are made when the benefits to investing in the programs are less than the alternative supply option. Various methodologies have been presented to assess whether a particular program is worthy of investment as opposed to investment in traditional supply resources, but the most commonly cited example comes from the *Standard Practice Manual: Economic Analysis of Demand Side Management Programs* developed by the utilities and regulators in California. This manual identifies a number of tests used to quantify the benefits and costs of conservation programs.

The Participant Test

Stated simply, the purpose of the Participant Test is to determine whether any Demand Side Management activity is cost effective from the standpoint of the individual or entity participating in the activity. This test is both the easiest to pass and the most fundamental to the success of a DSM program. It is easiest to pass in the sense that no considerations other than those that involve the directed affected individual or entity enter into the calculation. It is most fundamental to the success of any program in the sense that failure to demonstrate quantifi-

[4] OGP denotes "Optimized Generation Program." This procedure determines for an electric utility the optimal selection of plant (e.g., oil, coal, nuclear, gas, peaker, boiler, combined-cycle, etc.) and plant size. The program considers load curves, fuel and capital costs, operation and maintenance costs, and other relevant factors. ROGM denotes "Raab Optimized Gas Model," and is a linear programming model for the selection of the most efficient selection of natural gas suppliers. There are a variety of vendors for such types of models.

able benefit to the participant will limit program participation.

Advantages:

1. Good "first cut" at the desirability of the program to customers.
2. Can be used to design minimum incentive levels.
3. Can be used to determine program participation rates.
4. Can determine whether fuel substitution programs are in the long-run best interest of the customer.

Disadvantages:

1. The test reflects only *quantifiable* benefits and costs to the customer and is therefore not a complete measure of the consequences of program participation.
2. The test may not reflect the true complexity of a customer's decision making process.

Comments:

The California *Standard Practice Manual* defines the benefits and costs that should be included in an application of the Participant Test. The benefits include "the reduction in the participant's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received." The manual states that if a program involves fuel switching, then benefits also include "the avoided capital and operating costs of the equipment/appliance not chosen." The costs to the participant include "all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s)."

Since these benefits accrue and costs are incurred over the life of the program, which is often greater than one year, it is appropriate to express the benefits and costs on a net present value basis. A discounted payback period can be calculated. The relationship of these costs and benefits expressed in present value terms can also be presented in difference form for the total program and on average as well as in ratio form.

The benefit and cost terms described above can be expressed mathematically in the following equations.

Equation 1

$$B_p = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_p = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

where:

BR	=	Bill reductions in year
BI	=	Bill increases in year
TC	=	Tax credits in year
INC	=	Incentives paid by sponsoring utility in year
PC	=	Participant costs in year (initial capital costs, sales tax, ongoing operation and maintenance costs, and net salvage)
PAC	=	Participant avoided cost in year for alternate fuel devices
AB	=	Avoided bill from alternate fuel in year.

There is also an additional feature of the California evaluations: the inclusion of gross and net impacts. The difference in these values is that impact would have occurred in the absence of the program. Program participants who would have implemented the program technology in the absence of incentives are referred to as "free riders." Thus, the gross and net distinction employed in the California evaluations is an attempt to measure the impact of free riders on program results.

The Non-Participant Test

The Non-Participant Test is sometimes referred to as the Rate Impact Measurement Test. As these names imply, the purpose of this test is to measure the degree to which individuals and entities who choose not to participate in the DSM programs of the offering utility will be affected.

This is often a restrictive test in the sense that many DSM programs will save energy. Since there are then fewer units over which to spread unchanged demand related costs (as well as program costs), the rates to all customers increase. To the extent that non-participants are not involved in a program to off-set these increases, they may be negatively impacted.

Many utilities have argued that if any program causes any ratepayer to be negatively impacted, the program should not be offered. This is the so-called "no losers" rule.

Those who disagree with this position argue that if all non-participants are free to participate in the programs offered by a utility, then the non-participants have the opportunity to lessen the impact of higher bills with savings resulting from participation in one or more of the offered programs. Furthermore, it is argued that if marginal costs exceed average costs, then implementation of any supply-side option will have negative rate consequences for all customers. Thus, if demand-side and supply-side options are evaluated equally, demand-side programs with negative rate consequences may be better from a least cost perspective than supply-side alternatives.

Even proponents of this test would probably not argue that it should not serve as the sole basis for deciding whether to implement a demand-side program, however. Rather, the test should be one of a group offered to determine the costs and benefits resulting from program implementation.

Advantages:

1. Determines the direction and magnitude of the expected change in customer bills or rate levels as a result of a DSM program.
2. The only test that reflects customer revenue shifts (cross-subsidization) as a result of lost revenues from conservation programs.
3. Can be used to evaluate *all* program types (conservation, load management, fuel substitution, and load building).

Disadvantages:

1. The test results may be less certain than other tests because the test is sensitive to long run marginal cost and rate projections.
2. The test results are sensitive to financing assumptions.
3. Under certain conditions (MC < AC), a program that promotes an inefficient appliance may give a more favorable result than a program that promotes an efficient appliance.
4. DSM programs with the sole intent of building load will pass the test.

Comments:

In order to implement this test, the California *Standard Practice Manual* defines benefits to include savings from avoided supply costs for all affected fuel types and any revenue gains that may result from a fuel switching program. Costs are defined in the Manual to be equal to "costs incurred by the utility, the incentive payments to the participant, decreased revenue for any periods in which load has been decreased and increased supply costs for any periods when load has been increased." The Manual also clearly states that "the decreases in revenues and increases in the supply costs should be calculated for both fuels for fuel substitution programs using net savings."

Again, benefits accrue and costs are incurred over many years during which the program under evaluation is in effect. Thus, present value is an appropriate way to express the results. However, the first year revenue impact may also be of interest. If so, the Manual states that this is an acceptable way to present the results. Results can also be expressed as a difference, a ratio, and on a per unit of energy saved basis.

The mathematical formulae that define these tests are as follows:

Equation 2

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + UC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

where:

UAC = utility avoided supply costs in year

UIC = utility increased supply costs in year

RG	=	revenue gain from increased sales in year
RL	=	revenue loss from reduced sales in year
UC	=	utility program costs in year
E	=	system sales.

The All Ratepayers Test

In many jurisdictions, the All Ratepayers Test (also known as the Total Resource Cost Test) serves as the primary evaluation tool for DSM programs. The purpose of the All Ratepayers Test is to measure the impact on all ratepayers (both participants and non-participants in the DSM programs offered by the sponsoring utility). Accordingly, the All Ratepayers Test can be computed as the sum of the benefit and cost terms of the participant and non-participant tests.

The California Manual notes that test results of the All Ratepayers Test "for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric)." The benefits to be included in the test are the avoided supply costs, valued at the marginal cost. Costs include all participant and utility costs, plus the increased supply costs if load is increased. "For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program."

Similar to the other tests, it is also appropriate to express the results of the All Ratepayers Test in net present value terms, as a ratio, or on a per unit of energy saved basis.

Advantages:

1. Measures the net costs of a Demand Side Management program as a resource option based on the total costs of the program.
2. Can be applied to conservation, load management, and fuel substitution programs.
3. When applied to fuel substitution programs, measures the economic efficiency implications of a program on the total energy (gas and electric) supply system.
4. The test is broad in scope and considers the impacts on <u>all</u> ratepayers (classes and fuel types).
5. The test provides a useful basis for comparing investments in demand-side options to investments in supply-side options.
6. Uncertainties associated with embedded rate projections are minimized.
7. DSM programs with the sole intent of building load will fail the test.

Disadvantages:

1. Cross-subsidies are not identified by the test.

Comments:

Mathematically, the test can be expressed in the following equations:

Equation 3

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t + UIC_t}{(1+d)^{t-1}}$$

where:

UAC	=	utility avoided costs
TC	=	tax credits in year
PAC	=	participant avoided cost in year for alternate fuel devices
UC	=	utility program costs in year
PC	=	participant costs in year (initial capital costs, sales tax, ongoing operation and maintenance costs, and net salvage)
UIC	=	utility increased supply costs in year.

A variant of the All Ratepayers Test relies on the fact that the All Ratepayers Test as described above is actually the sum of the Participant Test and the Non-Participant Test, after appropriate mathematical simplification. The simplification requires that lost revenues by alternate fuel suppliers be cancelled with bill savings of consumers of the alternate fuel. In mathematical terms:

Equation 4

$$B = BR + TC + INC + AB(af) + PAC(af) + UAC + RG + UAC(af)$$
$$C = PC + BI + UIC + RL + UC + INC + RL(af)$$

where all variables are defined as before. To simplify these equations, set $TC = 0$, cancel BR in the B equation and RL in the C equation, cancel RG in the B equation and BI in the C equation, and subtract the incentive (INC) from both equations. This leaves:

Equation 5

$$B = AB(af) + PAC(af) + UAC + UAC(af)$$
$$C = PC - INC + UIC + UC + INC + RL(af)$$

If we now define the following variables:

PC' =	participants cost above the incentive amount
UC' =	utility cost including the incentive
$RL(af)$	= 0
$PAC(af)'$	$= PAC(af) + AB(af)$

this leaves:

Equation 6

$$B = UAC + UAC(af) + PAC(af)'$$
$$C = PC' + UIC + UC'$$

This formulation of the All Ratepayers test recognizes that in all cases the alternative fuel supplier is in a growth mode. Therefore, they experience no real revenue loss.

The Utility Cost Test

This test defines costs narrowly and measures the net cost incurred by a utility of a Demand Side Management program as a resource option. The purpose of the Utility Cost Test is to determine the actual cost to the utility of a particular Demand Side Management activity.

The benefits include the avoided supply costs. In the case of fuel substitution programs offered by a combination utility, benefits also include the avoided supply costs of the alternate fuel. In the case of a fuel substitution program in which two competing utilities are involved, only the benefits associated with the avoided costs of the primary fuel are included. This differs from the treatment of avoided costs in the All Ratepayers Test presented above, but is logically consistent. The consistency stems from the fact that benefits to all ratepayers logically include all benefits, including those that result from substitution applications. On the other hand, benefits to a utility offering the program only include those benefits that will logically accrue to the utility.

Costs in the Utility Cost Test include all out-of-pocket costs incurred to implement the program and include "the program costs incurred by the utility, the incentives paid to the customers, and the increased supply costs for the periods in which the load is increased."

Since these benefits accrue and costs are incurred over the life of the program, which is often greater than one year, it is appropriate to express the benefits and costs on a net present value basis. A discounted payback period can be calculated. The relationship of these costs and benefits expressed in present value terms can also be presented in difference form for the total program and on average as well as in ratio form.

Advantages:

1. Measures the net costs of a Demand Side Management program as a resource option based on the utility's costs of the program.
2. Uncertainties associated with embedded rate projections are minimized.
3. DSM programs with the sole intent of building load will fail the test.

Disadvantages:

1. The test understates the true cost of acquiring the resource since it excludes participant costs.
2. Cross-subsidies are not identified by the test.

Comments:

The benefit and cost terms of the utility cost test can be expressed mathematically as follows:

Equation 7

$$B_{UC} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$
$$C_{UC} = \sum_{t=1}^{N} \frac{UC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

where:

UAC = utility avoided costs

UC = utility program costs in year

INC = utility incentive payments

UIC = utility increased supply costs in year.

The Societal Test

This test includes the consideration of externalities among the costs and benefits.

Advantages:

1. Measures the net costs of a Demand Side Management program as a resource option based on the total societal costs of the program.
2. Can be applied to conservation, load management, and fuel substitution programs.
3. When applied to fuel substitution programs, measures the economic efficiency implications of a program on the total energy (gas and electric) supply system.
4. The test is broad in scope and considers the impacts on *all* segments of society (including different fuel types).
5. The test provides a useful basis for comparing investments in demand-side options to investments in supply-side options from a societal perspective.
6. Uncertainties associated with embedded rate projections are minimized.
7. DSM programs with the sole intent of building load will fail the test.
8. The program can incorporate externalities.

Disadvantages:

1. Cross-subsidies are not identified by the test.
2. The results of the test may be less reliable because they rely on the quantification of externalities, by definition an unmeasurable effect.

Programs and Program Selection

A wide variety of conservation and Demand Side Management programs are available for implementation by both electric and gas utilities, individually or in some cases jointly. Such programs usually include some type of subsidy or payment to the participant to induce the undertaking of some type of conservation action. The actual delivery of programs is frequently implemented through subcontractors and existing trade channels. Programs are frequently focused on all energy consuming sectors, including residential, commercial, multifamily, industrial, and possibly other major users. In the case of the gas utility industry such programs have included:

- Higher efficiency furnaces for space heating in both the residential and commercial sectors
- Building shell modifications, including insulation, weatherization (i.e., weatherstripping, caulking, etc.), window improvements and replacement, and building design improvements
- Behavior modification, including time-of-use rates and equipment cycling for the shifting of loads to off peak periods, energy audits, clock thermostats
- Equipment modifications, including higher efficiency equipment—such as improved hot water heaters and clothes dryers, and electronic ignition for ranges and ovens instead of pilot lights.

Significant levels of expenditures can occur in the implementation of programs—millions of dollars. In general, programs are required to pass the economic efficiency tests discussed above, typically the All Ratepayers test. A successful program will frequently increase rates, but will also decrease consumption; and the decrease in consumption will offset the higher cost per unit.

The objectives that support DSM programs can be summarized as follows:

- To provide only those programs that have a high probability of being cost effective
- To provide programs that can demonstrate energy savings that reflect on customer bills
- To minimize the incidence of unnecessary incentives
- To maximize free-drivership

- To provide programs to consumers that emphasize the best energy value
- To minimize the chance for cross-subsidies, both between jurisdictions and between customer classes.

The reason for the first objective is simple and related to basic economics: if programs are being offered that are not cost effective, then all parties are harmed, and not helped, as a result. Ratepayers are harmed if they are required to shoulder cost burdens that are higher than they would be in the absence of conservation programs. Shareholders are harmed both by virtue of the fact that they are asked to absorb part of the cost for uneconomic activities as well as by the loss in market share that comes from uneconomic prices.

Requiring programs actually to save energy (and additionally requiring that these savings be measurable) is a necessary condition for the demonstration of cost effectiveness. Thus, this second objective goes hand-in-glove with the first objective. However, this objective goes beyond the issue of cost effectiveness. It requires that savings not be generated by engineering models (which tend to over-estimate savings). It further requires that savings not be generated by judgment (which can argue for the approval of any program). In short, this objective requires the program to produce measurable savings and these savings are defined as reductions in consumers' bills. The precise measurement of how this is done will be provided under a description of the programs below.

The payment of incentives to individuals who would engage in an activity that a conservation program is trying to promote in the absence of that incentive results in incentive dollars that are needlessly spent to encourage program participation. The consequences of this problem are clear: money is needlessly spent. This has the effect of diluting the cost effectiveness of any proposed conservation programs. In practice, it is impossible to eliminate free riders from conservation programs. Therefore, the objective becomes one minimizing the incidence of such participants. This is done through careful evaluation of the incentives involved, and continually monitored as part of the routine evaluation process.

Closely related to the concept above are free-drivers. Free-drivers engage in the conservation activities designed to be promoted by conservation programs, but do so without the payment of incentives. Free-drivers are generally assumed to engage in such behavior because of the greater conservation awareness or competitive advantage engendered by an IRP program.

In order to offer programs that support the concept of providing consumers the best energy value, it is crucial that all energy sources (all fuels) are considered in the cost effectiveness evaluations. Once again, the rationale for this thinking is clear. The imposition of IRP programs to change consumer behavior involves the tinkering with the free-market system. To the extent that this tinkering results in a worse allocation of resources than would otherwise occur, then any benefits to be gained from the imposition of such programs will vanish. In order to minimize the deleterious effects of such tinkering, the broadly defined energy market must be considered.

In order to minimize the chance for cross-subsidies, both between jurisdictions and between customer classes, it is imperative that the costs of the IRP programs being offered are assigned correctly to the class or jurisdiction that is benefiting from the program. For example, the payment of incentives to residential ratepayers for the installation of more efficient appliances provides benefits (as determined by an All Ratepayers/Total Resource Cost Test) to residential ratepayers (the incentive itself) and to other classes (the system savings associated with the program). While the correct assignment of costs and benefits is largely a judgmental matter, it is important that the assignment be carefully done so as to minimize any cross-subsidization that takes place.

Conservation Program Evaluation Techniques

IRP and DSM programs are generally evaluated in terms of two approaches: process evaluation and impact evaluation.

Process evaluations are concerned with a program's design and operational efficiency. There is emphasis on critically examining customer and utility/contractor staff reaction to the program. The procedure determines the extent to which customers are satisfied with the programs offered. A process evaluation typically addresses some of the following issues: customer satisfaction and attitudes, effectiveness of promotions and incentives, measurement of impacts, comprehensiveness, operational efficiency of utility staff, implementation effectiveness, and program participation.

Impact evaluations determine how much energy is actually saved by implementing the programs. This is critical because energy savings will have a direct bearing on the cost effectiveness of the dollars invested. The criteria used to measure the impact evaluation include participation, energy savings of the participants, and comparisons with control groups.

Overall Plan Integration

Since IRP requires utilities to investigate both demand-side options as well as supply-side options in determining the most cost effective investment options to deliver energy service to customers, each utility has to model decision making based on the availability of both resource options. To the degree that demand-side resources meet customer energy needs and are more cost effective than supply-side investment options, the utility decision making model should focus on more demand-side investment. When supply-side resources provide greater value, those resources should be included in the investment mix. A long run equilibrium model will ideally identify a mix of both supply-side and demand-side resources to meet customer energy needs.

The various available supply, demand, DSM choice, and other needs are typically simulated in a general equilibrium environment. The resulting solution then identifies optional levels of demand and supply resources.

OUTLOOK FOR GAS UTILITY INTEGRATED RESOURCE PLANS

IRP has now been extended to local gas distribution companies. This has been causing major changes in the way in which gas companies approach their business:

- First, IRP proceedings typically involve negotiation in working groups with intervenors who previously have typically been on an adversarial basis in regulatory hearings. To the degree that working groups can resolve controversial issues and arrive at economically efficient solutions, the consumer interest is well served.
- Second, LDCs have incurred significant expenses in program development and implementation. In some cases programs are expensed, and in other cases they are accrued or capitalized. Cost recovery of these expenses is necessary to ensure a continued level of commitment by top management to the process.

As the LDCs continue to pursue IRP there will be a number of discoveries. For example, there are differences between the gas and electric businesses. Many LDCs have declining marginal cost curves. The major savings may be energy savings rather than capacity savings, assuming that no additional pipelines need to be built. The plans are very similar to electric utility plans. The major difference is that gas utility declining cost mode makes direct gas conservation somewhat less dramatic than it would be in an increasing cost mode. There is no reason to believe that major new amounts of pipeline capacity need to be built to serve residential and commercial loads, and therefore evaluation under an increasing marginal cost would be inappropriate.

When assessing the level of benefits achieved through IRP for gas utilities and the distribution of those benefits, some additional differences emerge. Since a smaller proportion of the savings are related to capacity changes, fewer benefits from demand-side investment transfer to non-participants of DSM programs. In some cases, non-participants will see cost increases to fund DSM exceed the capacity savings; both their rates and their bills could go up.

Where combination electric and gas utilities exist, the greatest coordination of DSM investment based on relative energy avoided costs and savings has occurred. For example, a number of combination utilities with growing electric peaks and a need for greater generating capacity have implemented DSM programs aimed at shifting commercial electric air conditioning customers to natural gas systems by providing incentives paid either totally out of electric ratepayer funding mechanisms or joint electric and gas ratepayer funding mechanisms based on the relative costs and benefits. IRP can save significant capital costs and improve economic efficiency by shifting some electric load to natural gas. This may also occur in cases where the benefits flow to the electric customers but the utilities are separate entities.

IMPLICATIONS FOR NPC STUDY

IRP will cause gas to be used more efficiently, reducing gas utility load per household. Similar results can be expected for other sectors. It is therefore clear that in the case of the residential and commercial sectors that total load will decline except to the degree that additional customers come on line. The implementation of IRP principles may result in the conversion of some load—possibly commercial gas air conditioning, and possibly some other types of residential or commercial load—to natural gas. This would not be predatory load building on the part of gas utilities but, rather, a free market decision by consumers based on cost justified, economically efficient rates. Under the California conservation procedures, pricing and DSM signals are sent to consumers based on economic efficiency; at this time, the economics appear to favor increased utilization of natural gas. Several principles emerge:

- First, IRP should cause substantial conservation. This conservation is good, for it enhances economic efficiency and improves the competitive position of most gas appliances as they compete for market share against electricity.
- Second, IRP may result in some fuel selection in favor of natural gas, to the degree that natural gas is the economically preferable choice after conservation to reduce high cost, peak electric consumption.

APPENDIX D

RESIDENTIAL REGIONAL GRAPHS*

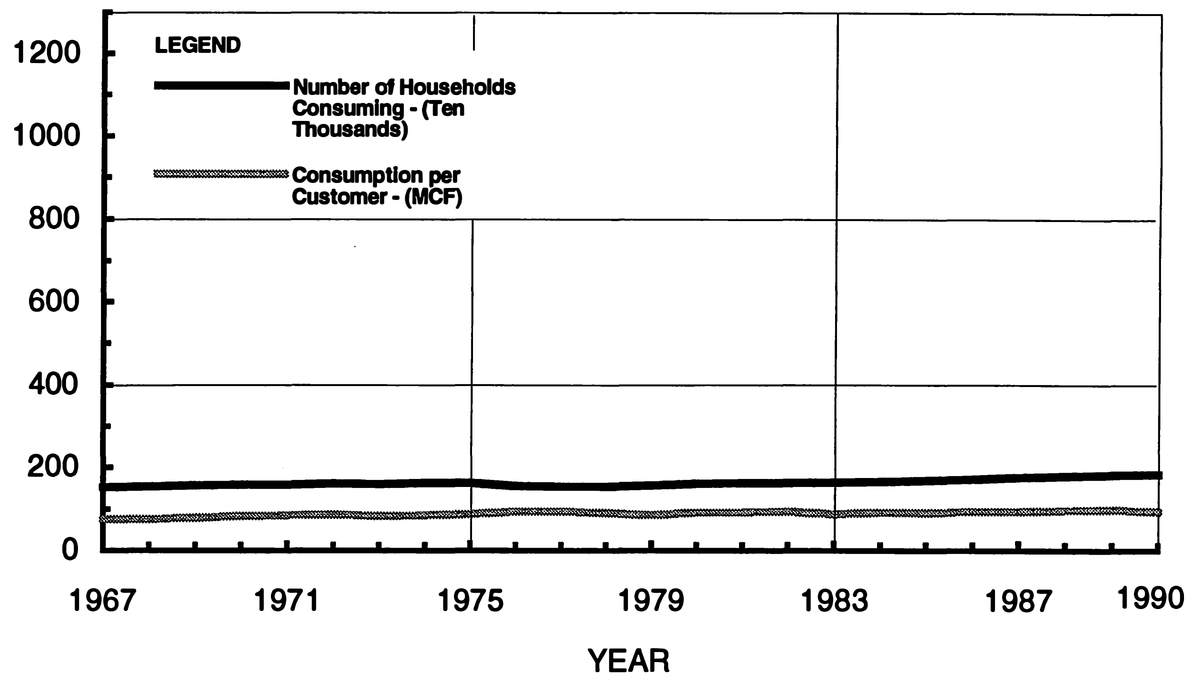
Consumption Per Customer & Number of Households Consuming

Regions 1-10

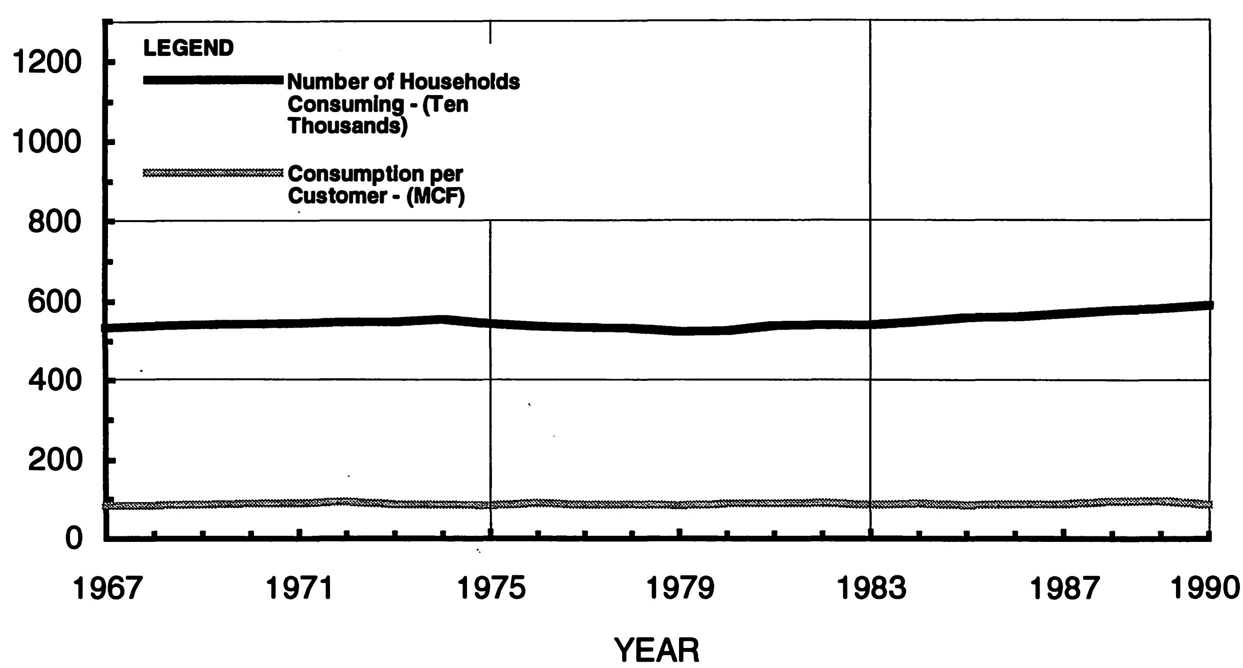
Region One:	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont
Region Two:	New York and New Jersey
Region Three:	Delaware, Pennsylvania, Maryland, Virginia, West Virginia, and District of Columbia
Region Four:	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee
Region Five:	Illinois, Indiana, Michigan, Ohio, Wisconsin, and Minnesota
Region Six:	Arkansas, Louisiana, Oklahoma, Texas, and New Mexico
Region Seven:	Iowa, Kansas, Missouri, and Nebraska
Region Eight:	Colorado, Utah, Wyoming, Montana, North Dakota, and South Dakota
Region Nine:	California, Arizona, and Nevada
Region Ten:	Idaho, Washington, and Oregon

* Graphs are based on historical data from the previous 20 years. The source for the data is Natural Gas Annual 1990, Volume 2, December 1991, DOE/EIA-0131(90)/2.

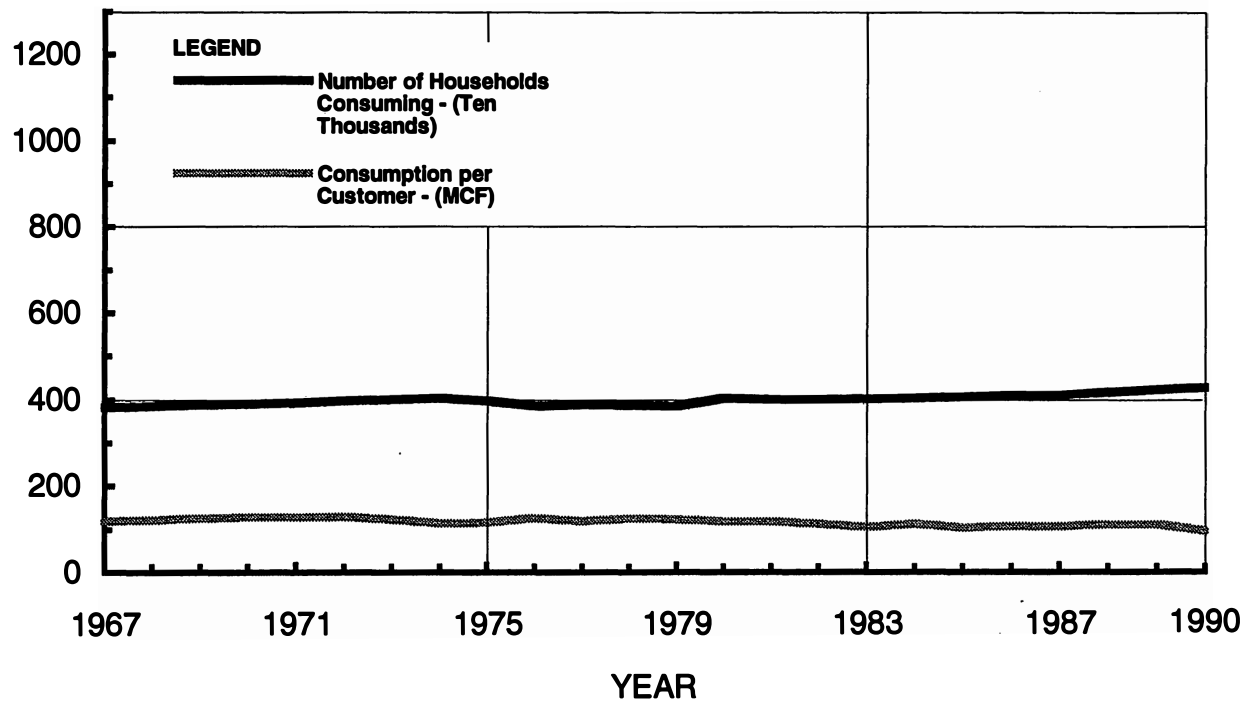
Region One
Consumption Per Customer & Number of Households Consuming.



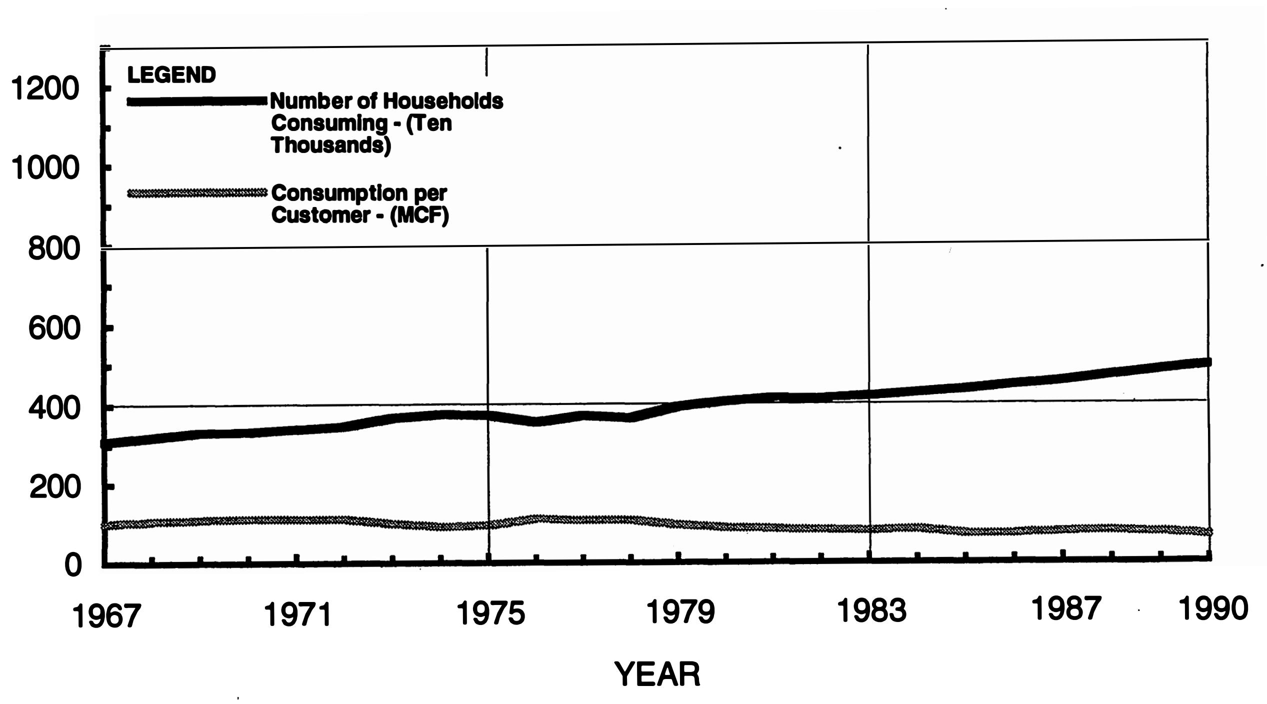
Region Two
Consumption Per Customer & Number of Households Consuming.



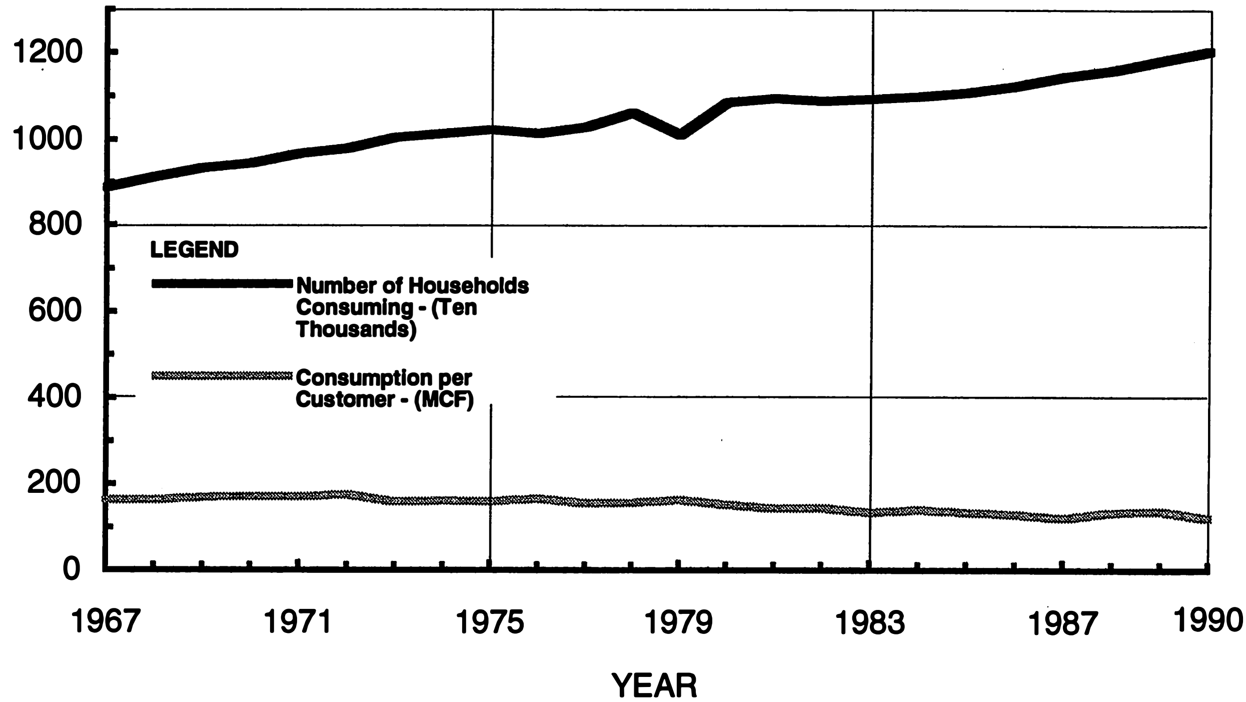
Region Three
Consumption Per Customer & Number of Households Consuming.



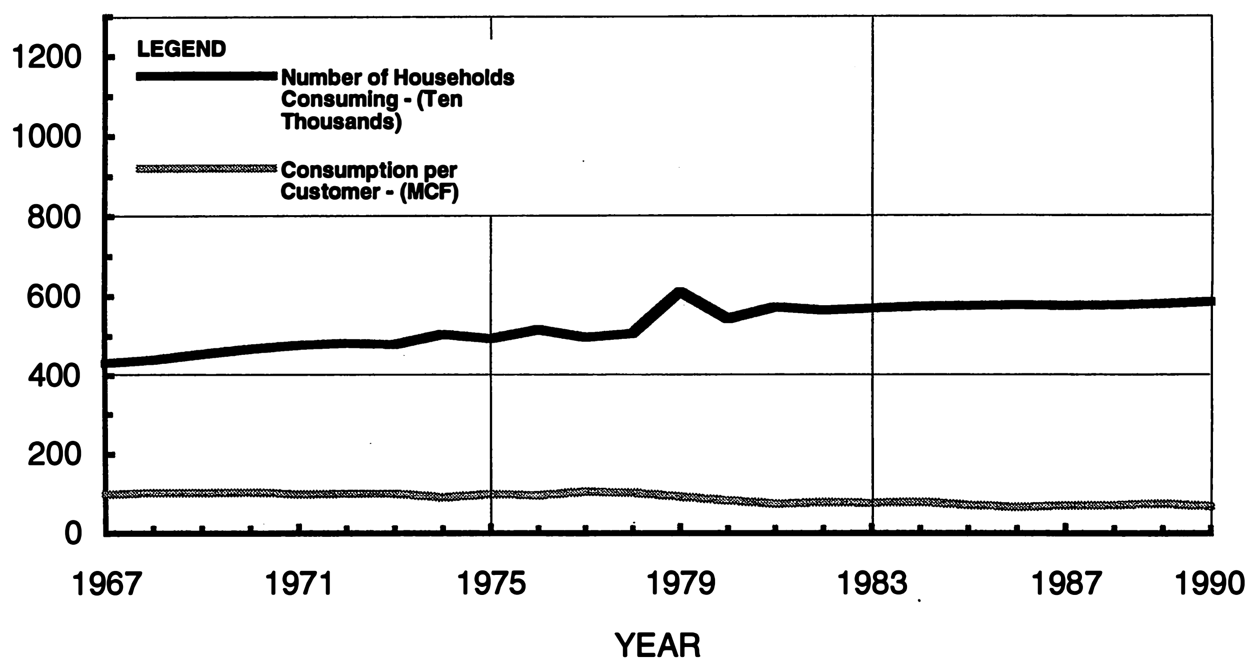
Region Four
Consumption Per Customer & Number of Households Consuming.



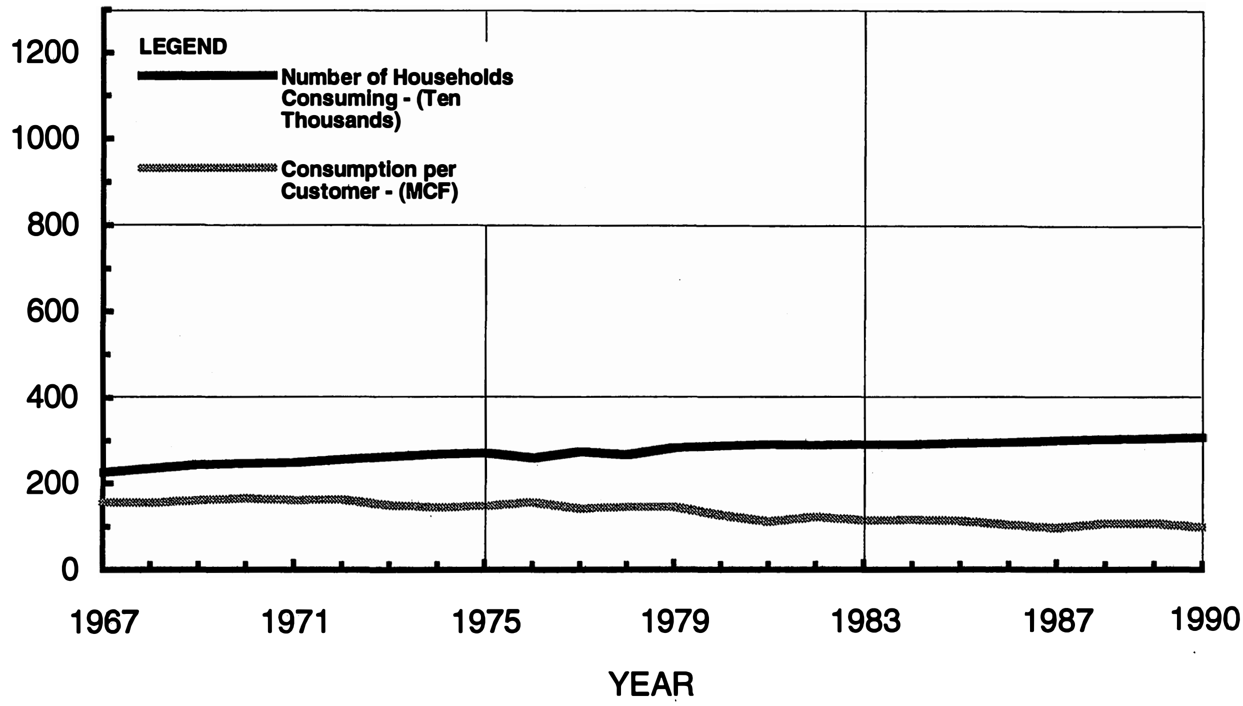
Region Five
Consumption Per Customer & Number of Households Consuming.



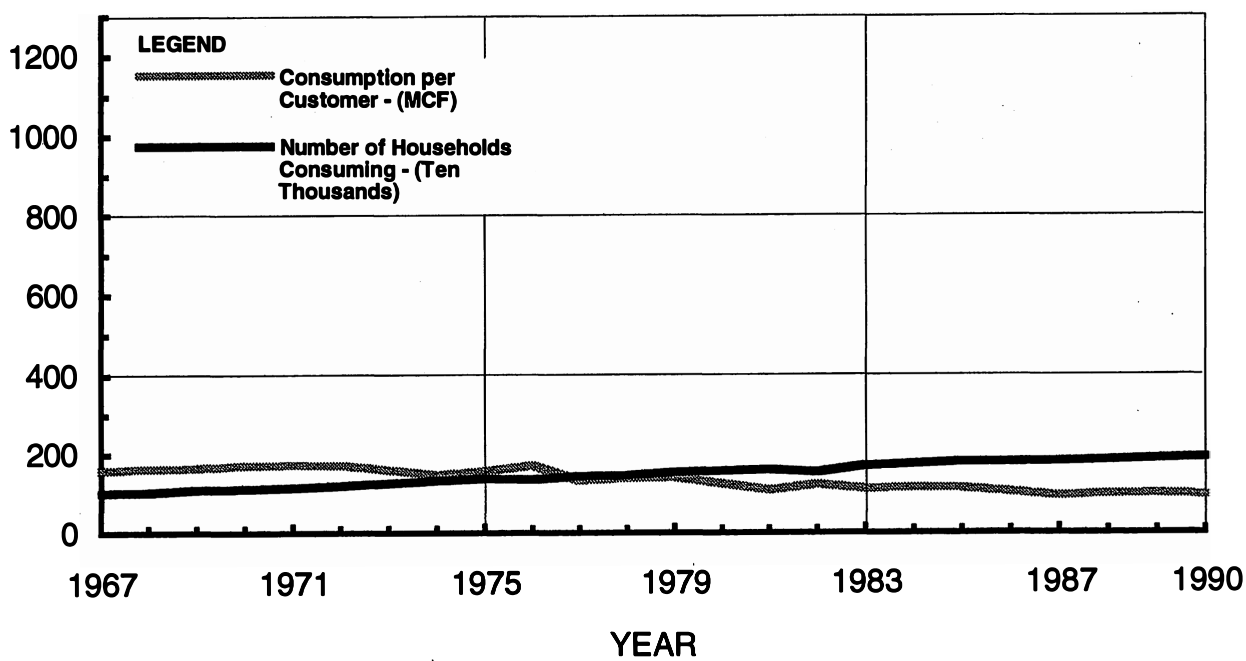
Region Six
Consumption Per Customer & Number of Households Consuming.



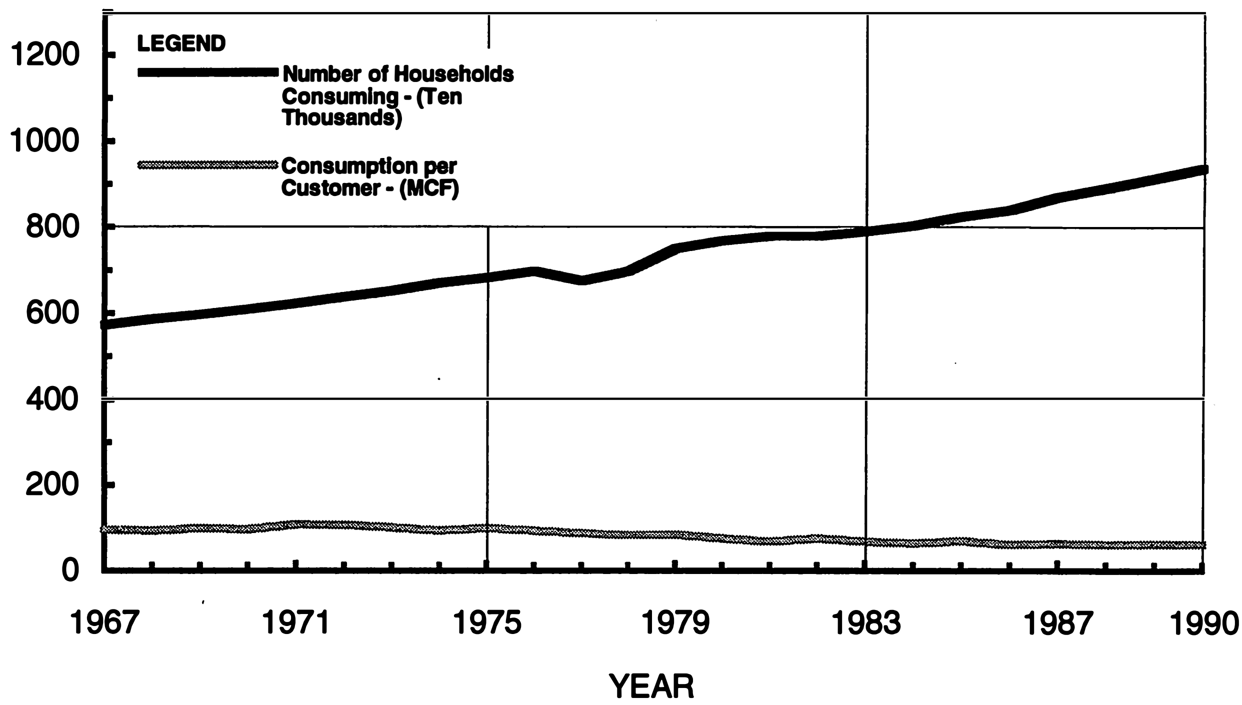
Region Seven
Consumption Per Customer & Number of Households Consuming.



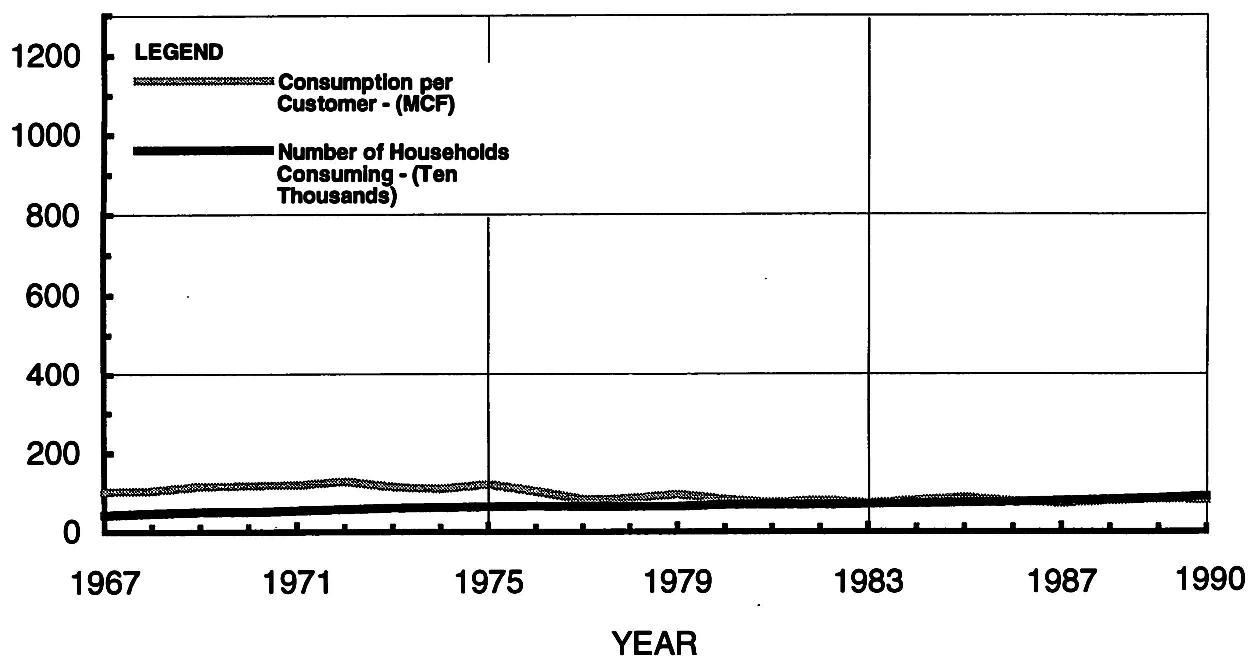
Region Eight
Consumption Per Customer & Number of Households Consuming.



Region Nine
Consumption Per Customer & Number of Households Consuming.



Region Ten
Consumption Per Customer & Number of Households Consuming.

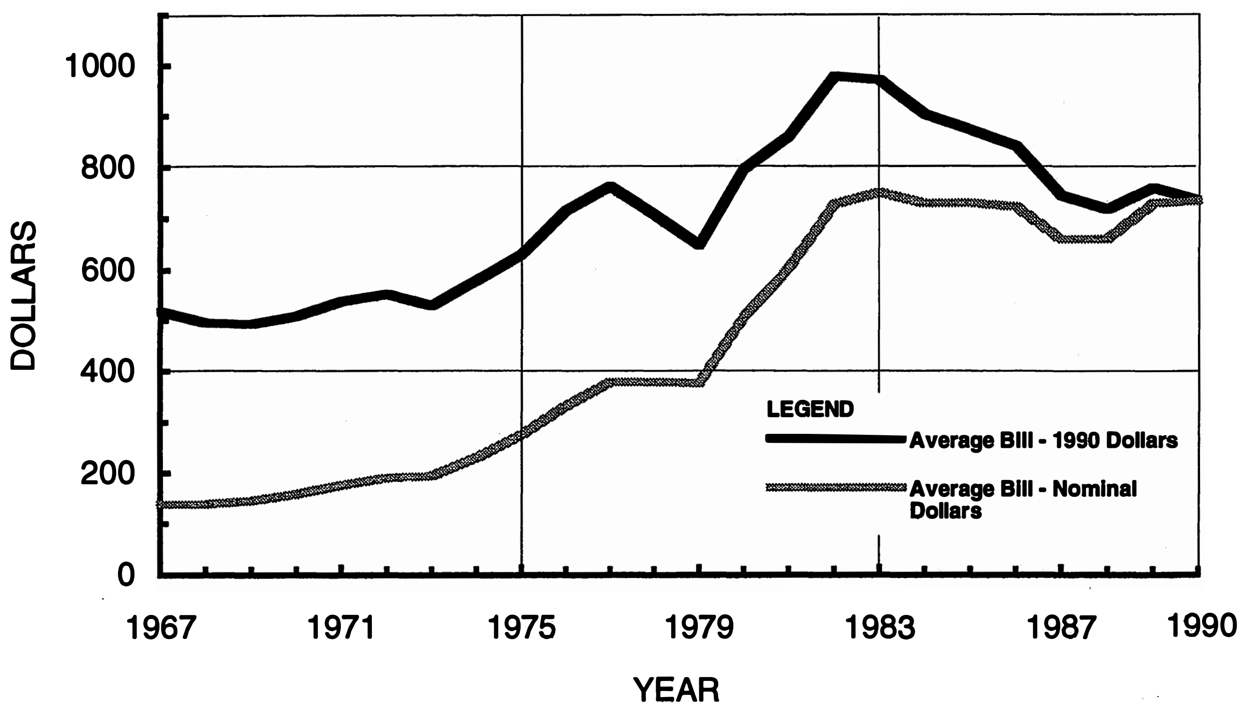


Average Bill Per Customer

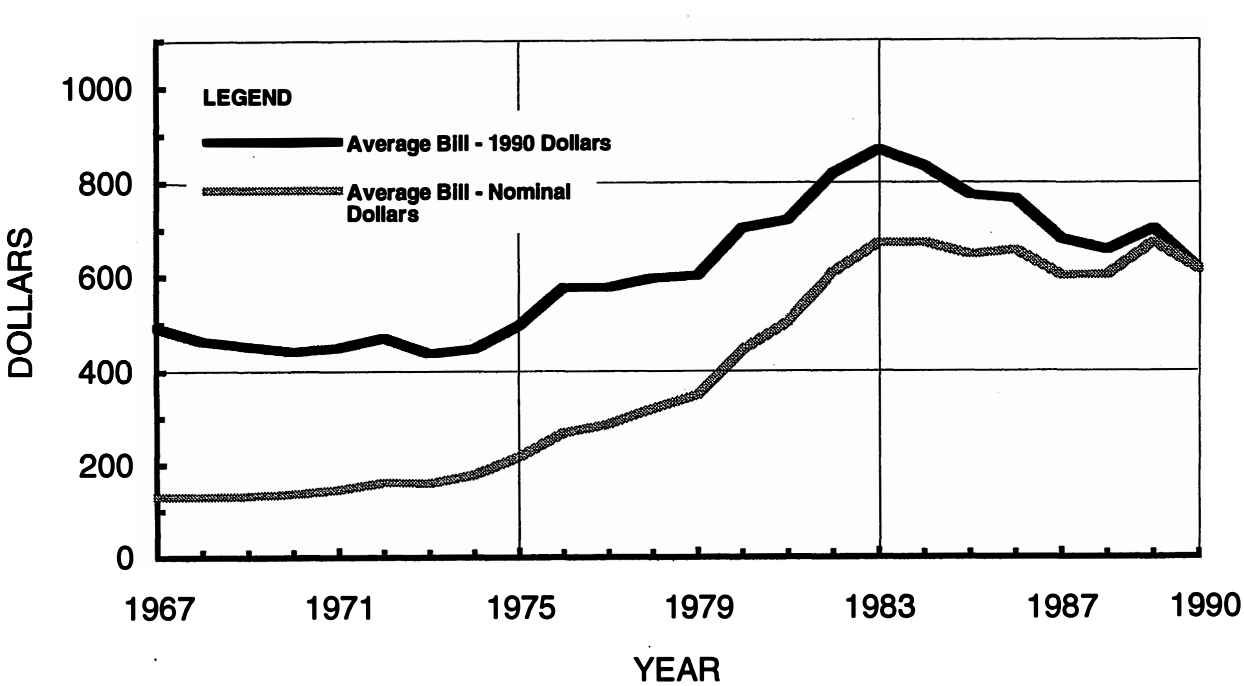
Regions 1-10

Region One:	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont
Region Two:	New York and New Jersey
Region Three:	Delaware, Pennsylvania, Maryland, Virginia, West Virginia, and District of Columbia
Region Four:	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee
Region Five:	Illinois, Indiana, Michigan, Ohio, Wisconsin, and Minnesota
Region Six:	Arkansas, Louisiana, Oklahoma, Texas, and New Mexico
Region Seven:	Iowa, Kansas, Missouri, and Nebraska
Region Eight:	Colorado, Utah, Wyoming, Montana, North Dakota, and South Dakota
Region Nine:	California, Arizona, and Nevada
Region Ten:	Idaho, Washington, and Oregon

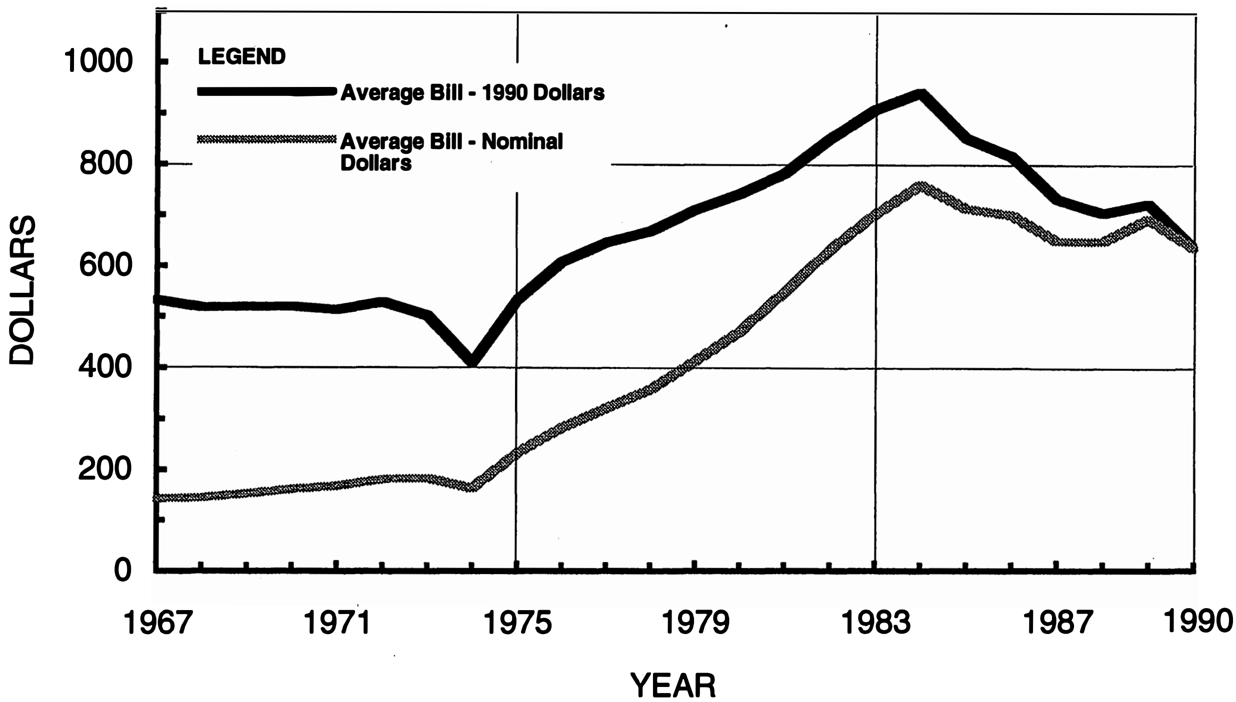
Region One
Average Bill Per Customer.



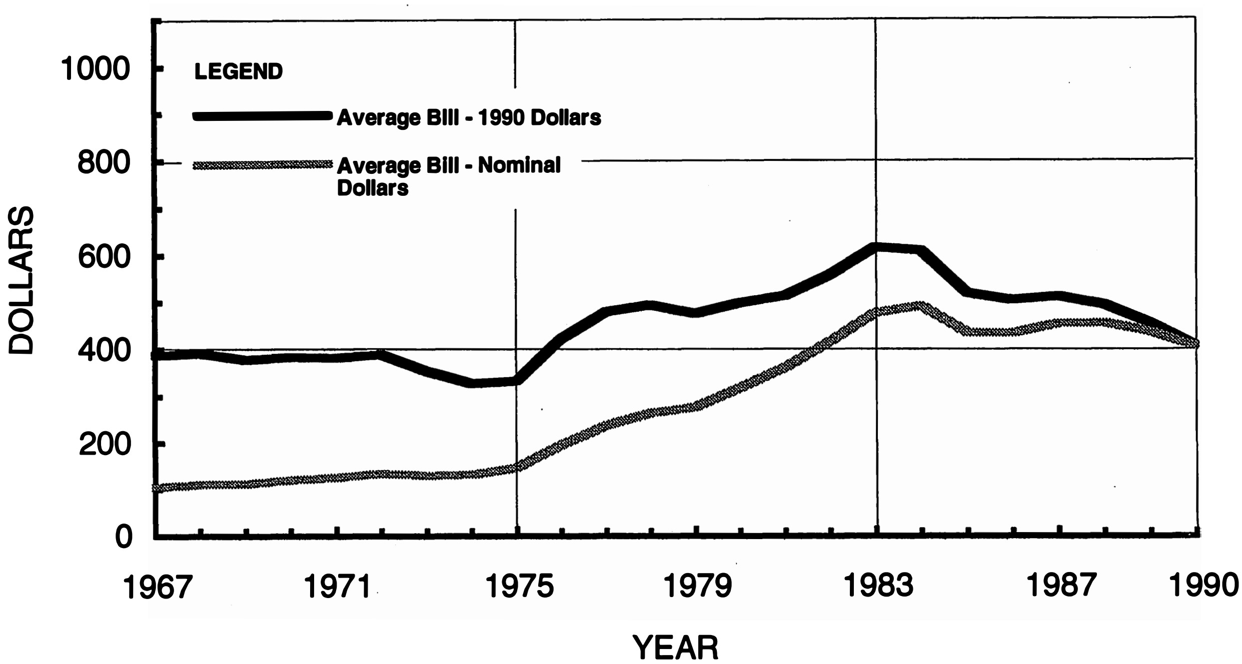
Region Two
Average Bill Per Customer.



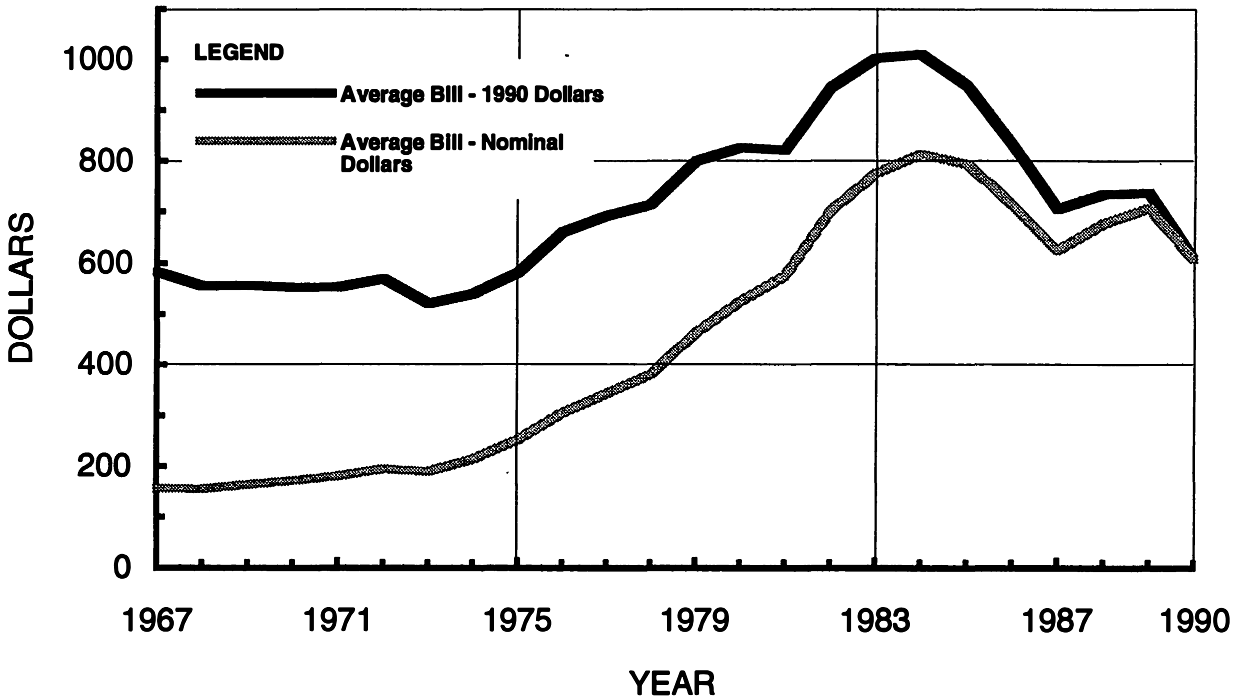
Region Three
Average Bill Per Customer.



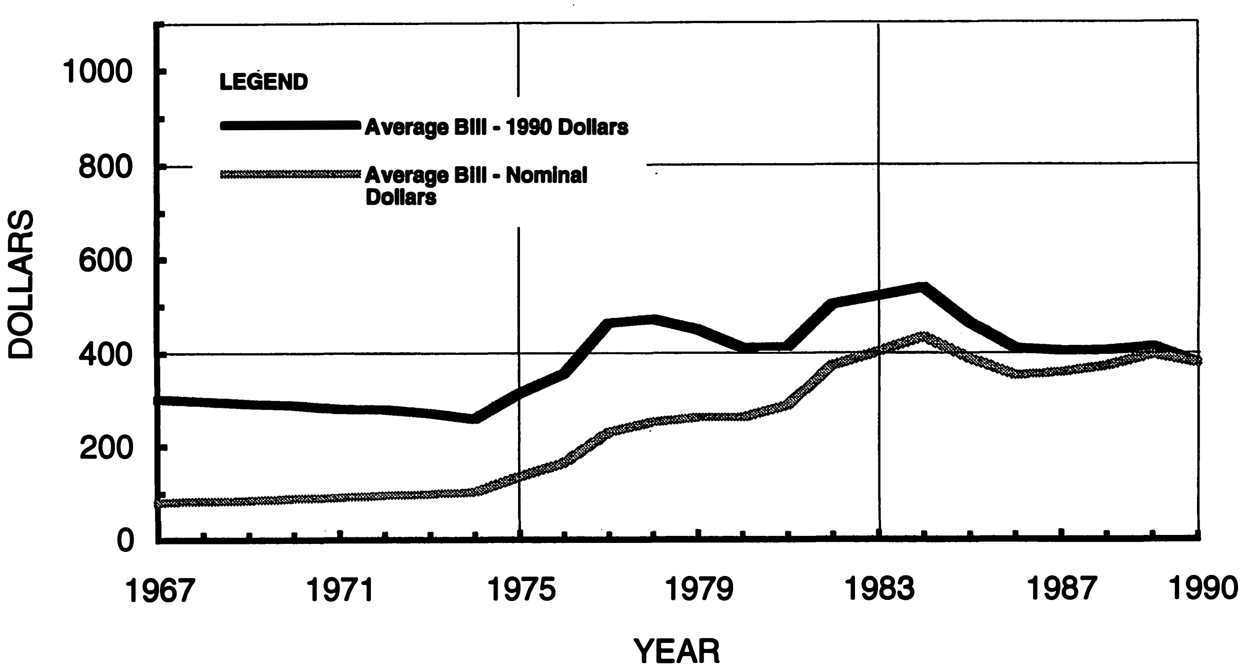
Region Four
Average Bill Per Customer.



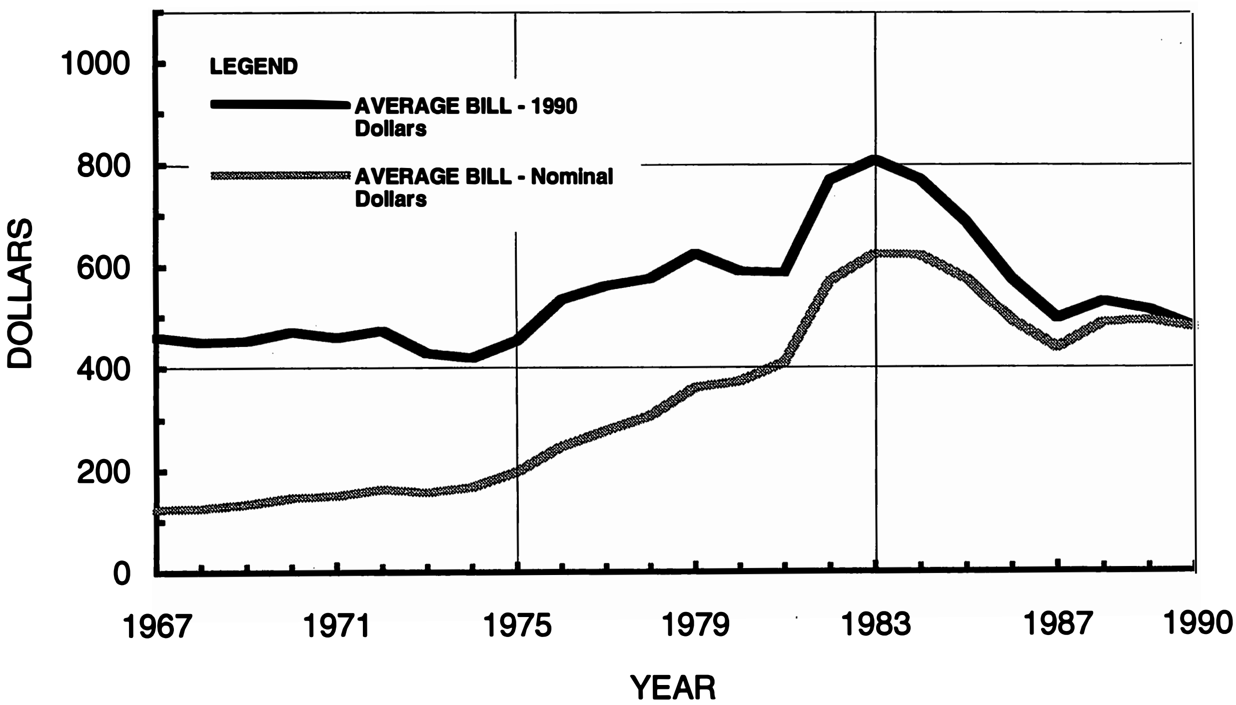
Region Five
Average Bill Per Customer.



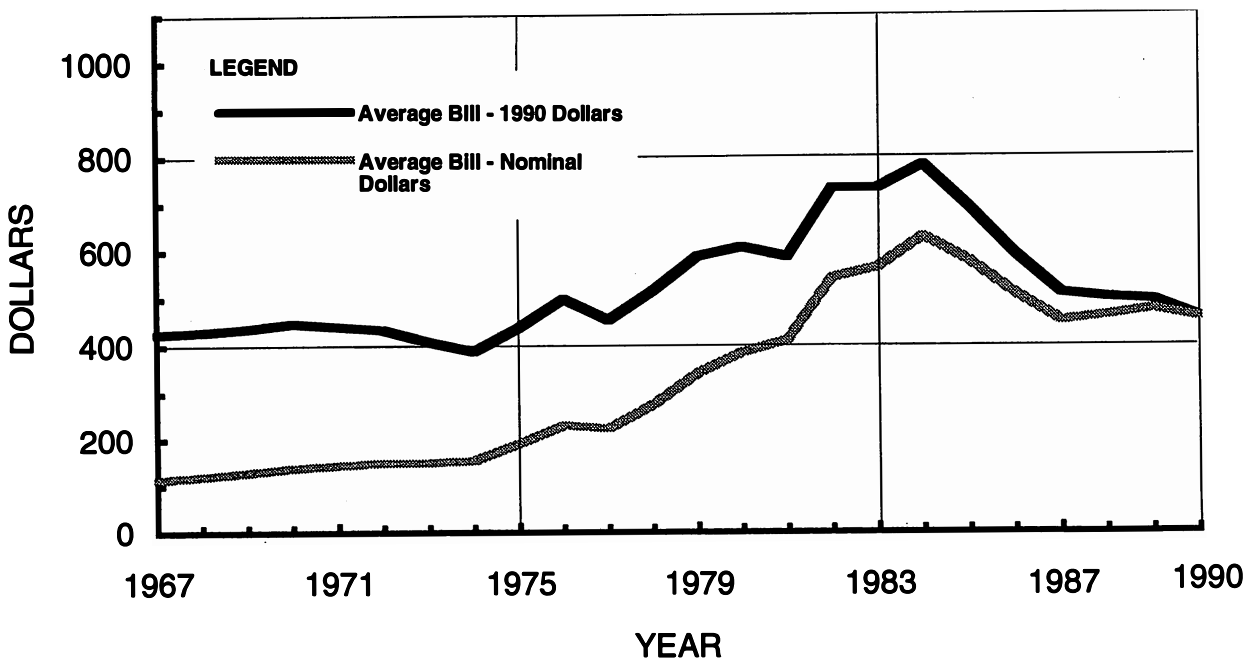
Region Six
Average Bill Per Customer.



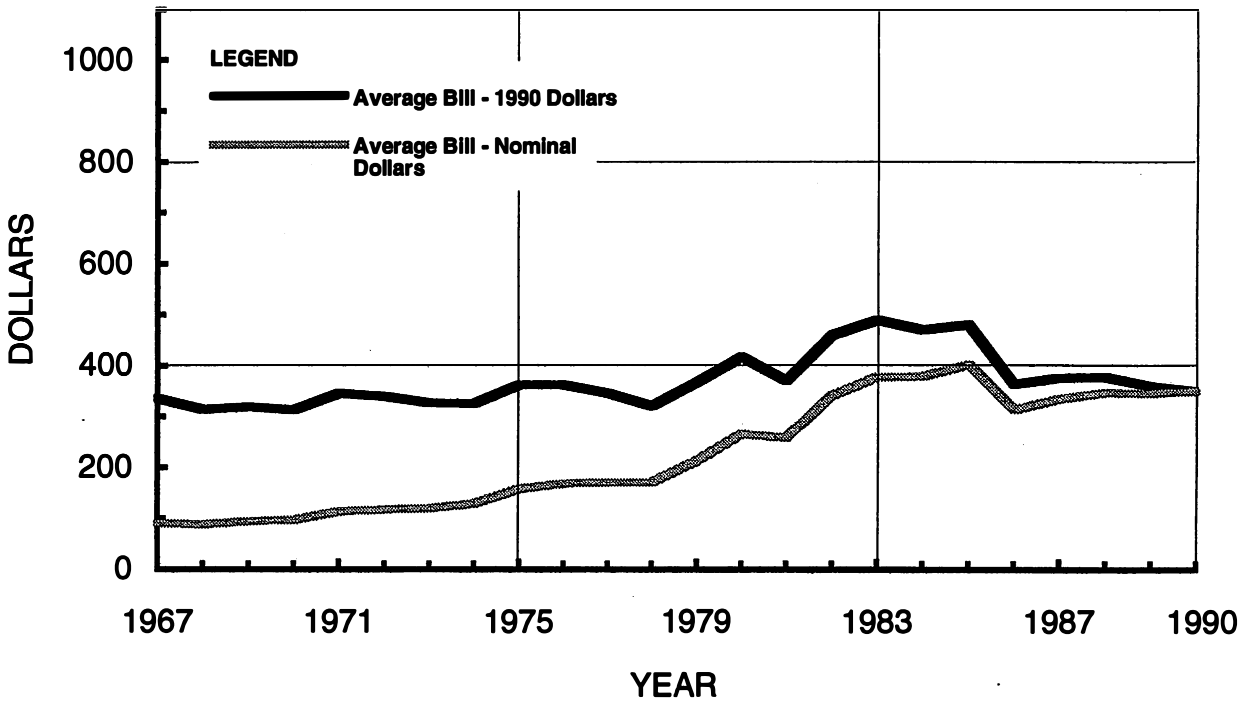
Region Seven
Average Bill Per Customer.



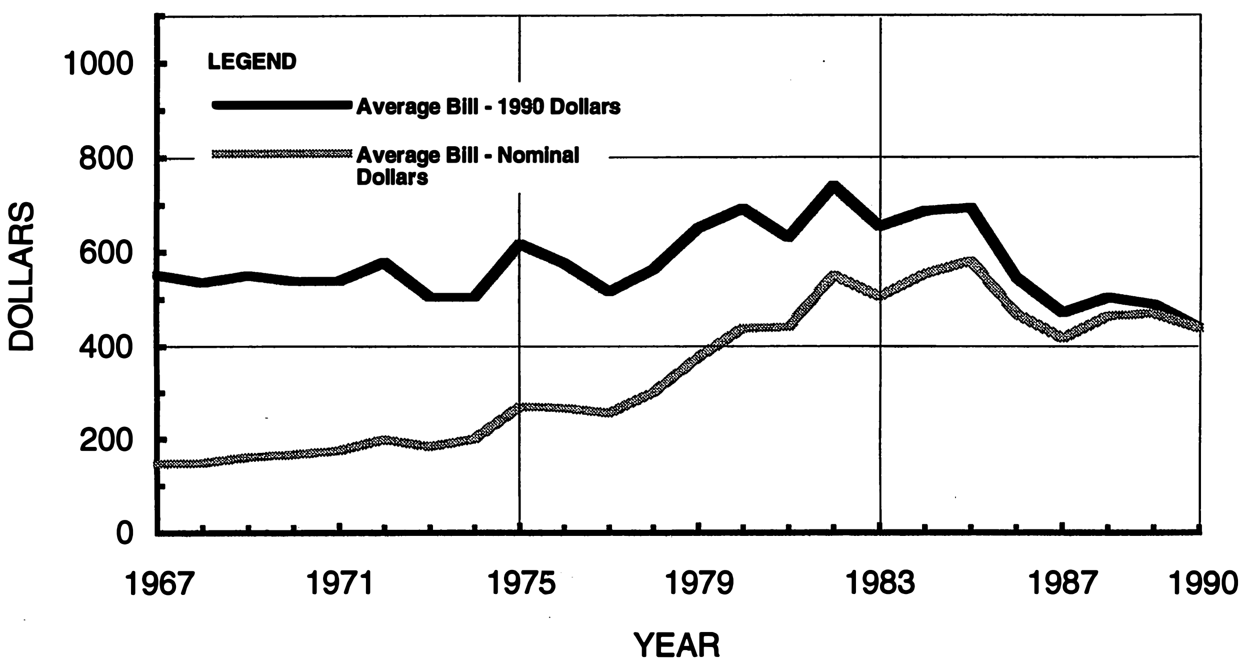
Region Eight
Average Bill Per Customer.



Region Nine
Average Bill Per Customer.



Region Ten
Average Bill Per Customer.

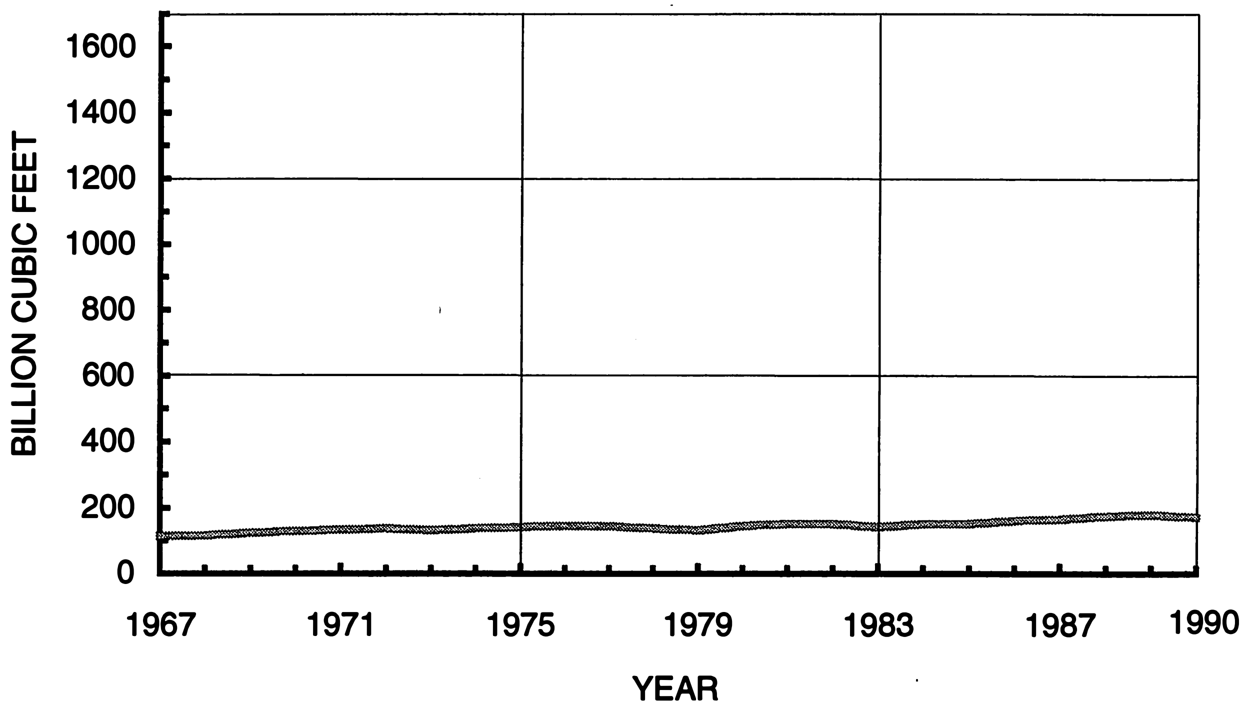


Total Consumption

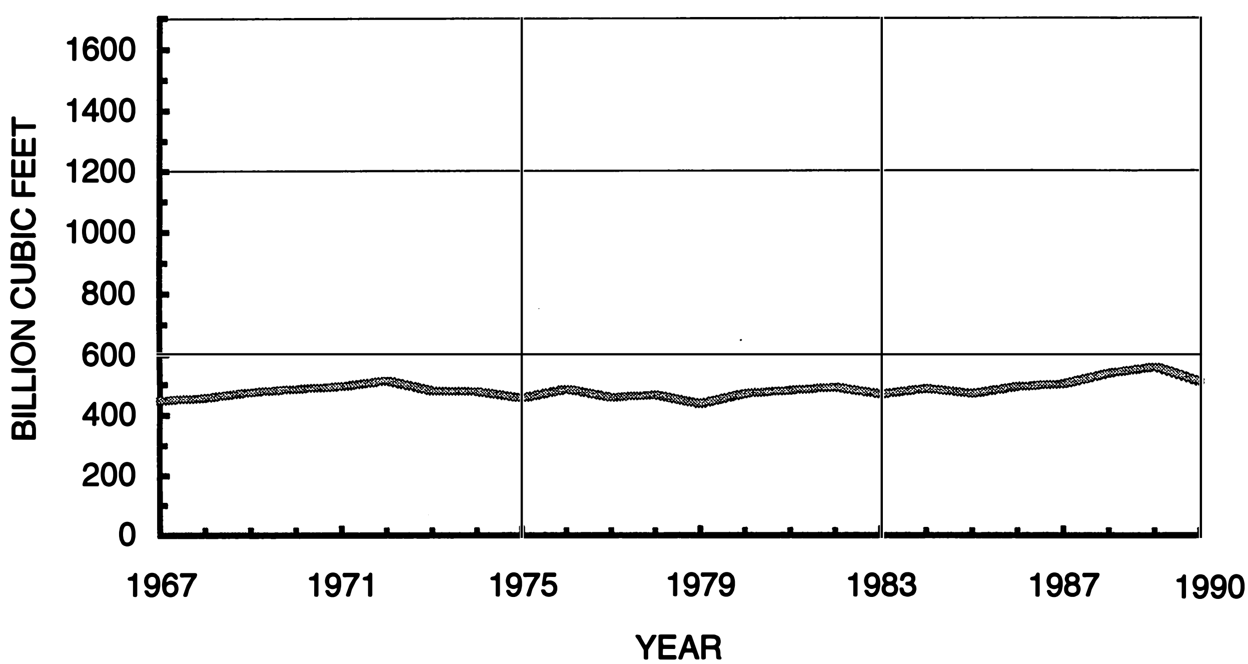
Regions 1-10

Region One:	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont
Region Two:	New York and New Jersey
Region Three:	Delaware, Pennsylvania, Maryland, Virginia, West Virginia, and District of Columbia
Region Four:	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee
Region Five:	Illinois, Indiana, Michigan, Ohio, Wisconsin, and Minnesota
Region Six:	Arkansas, Louisiana, Oklahoma, Texas, and New Mexico
Region Seven:	Iowa, Kansas, Missouri, and Nebraska
Region Eight:	Colorado, Utah, Wyoming, Montana, North Dakota, and South Dakota
Region Nine:	California, Arizona, and Nevada
Region Ten:	Idaho, Washington, and Oregon

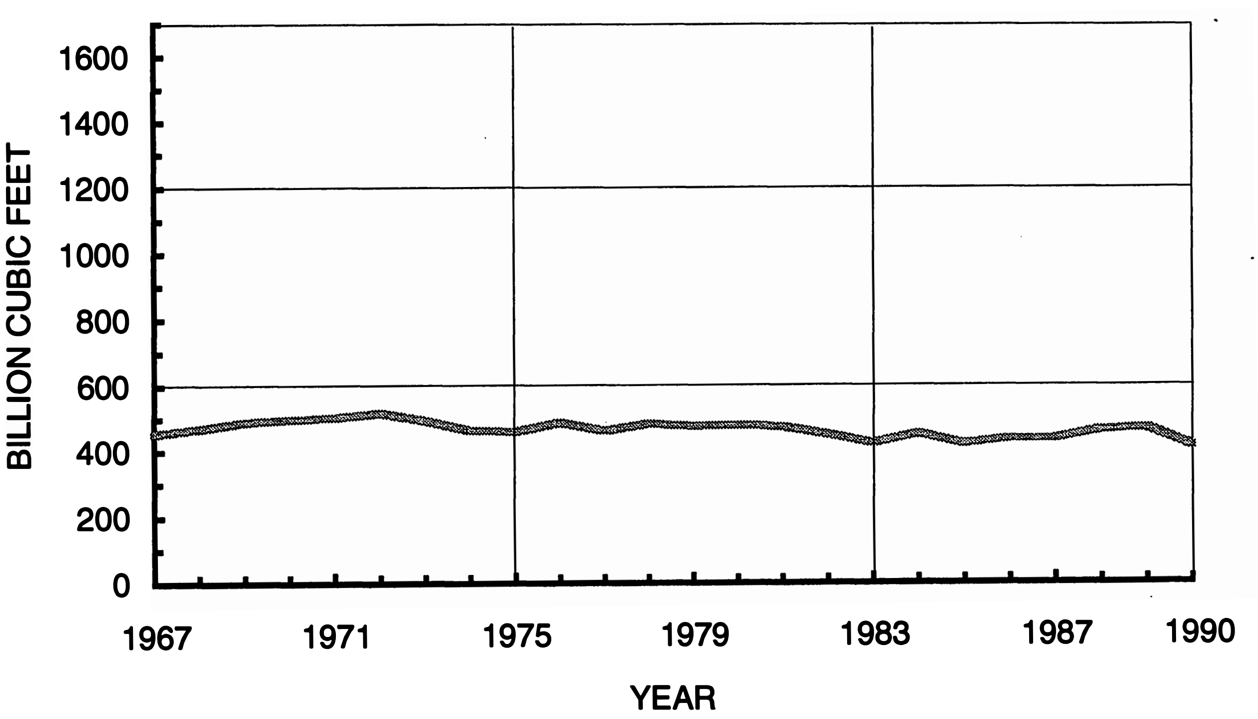
Region One
Total Consumption.



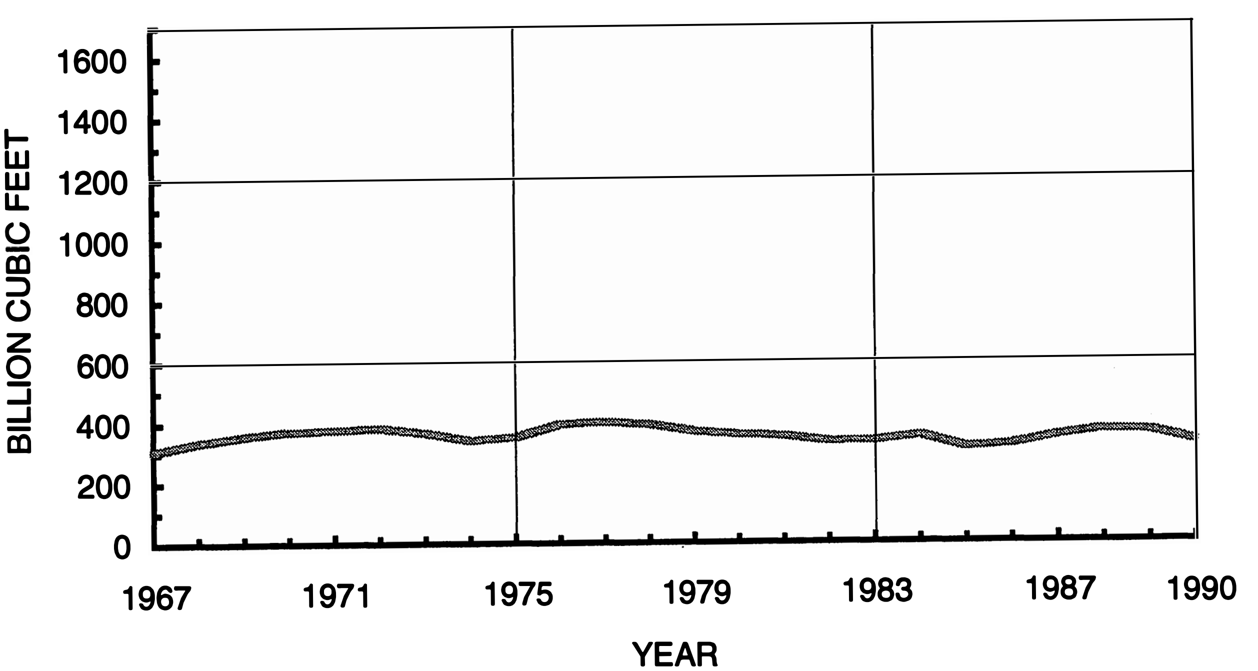
Region Two
Total Consumption.



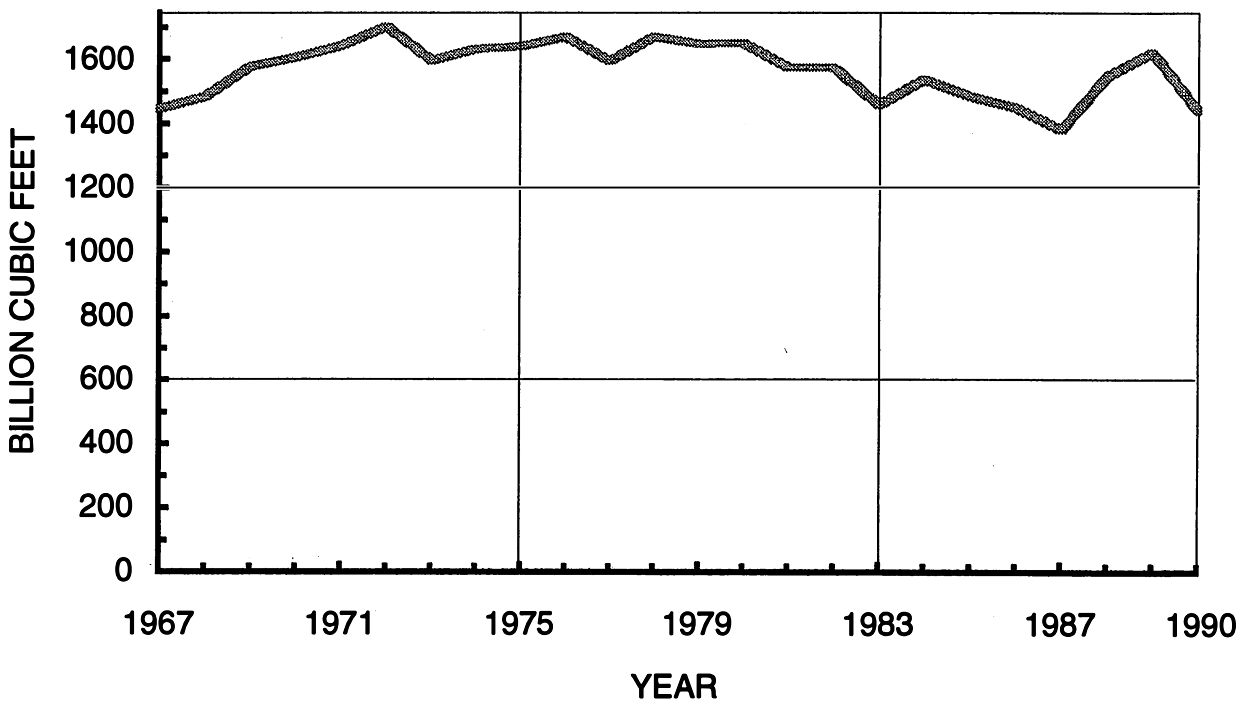
Region Three
Total Consumption.



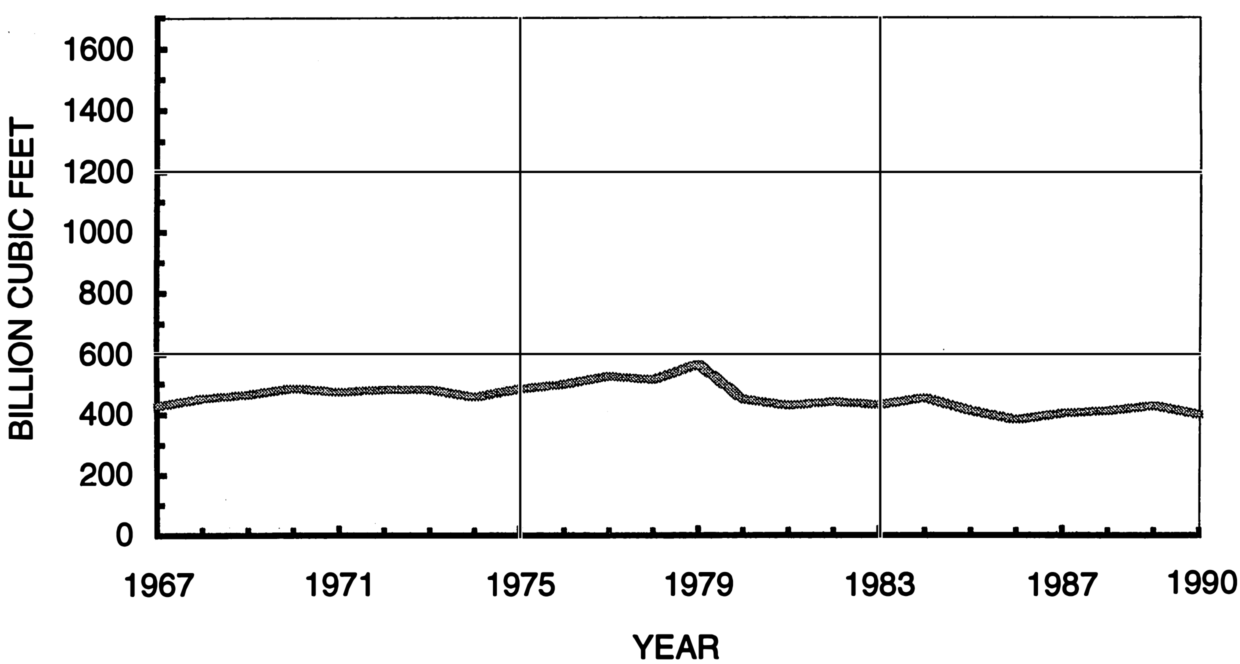
Region Four
Total Consumption.



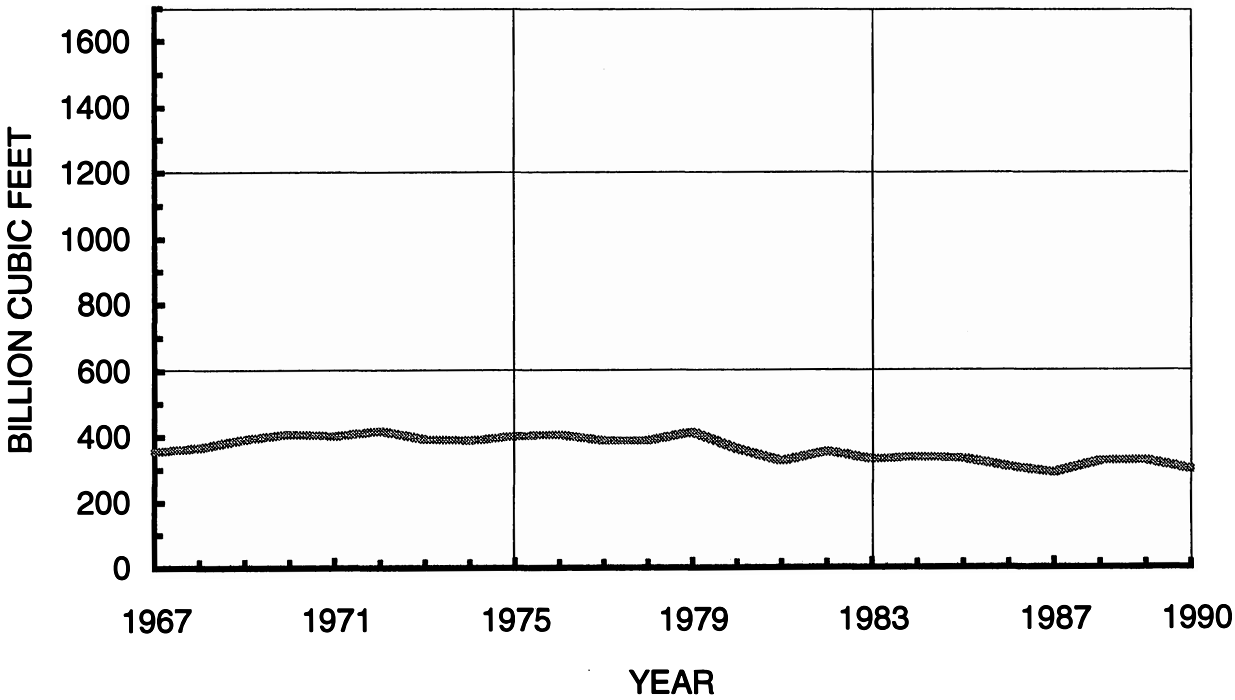
Region Five
Total Consumption.



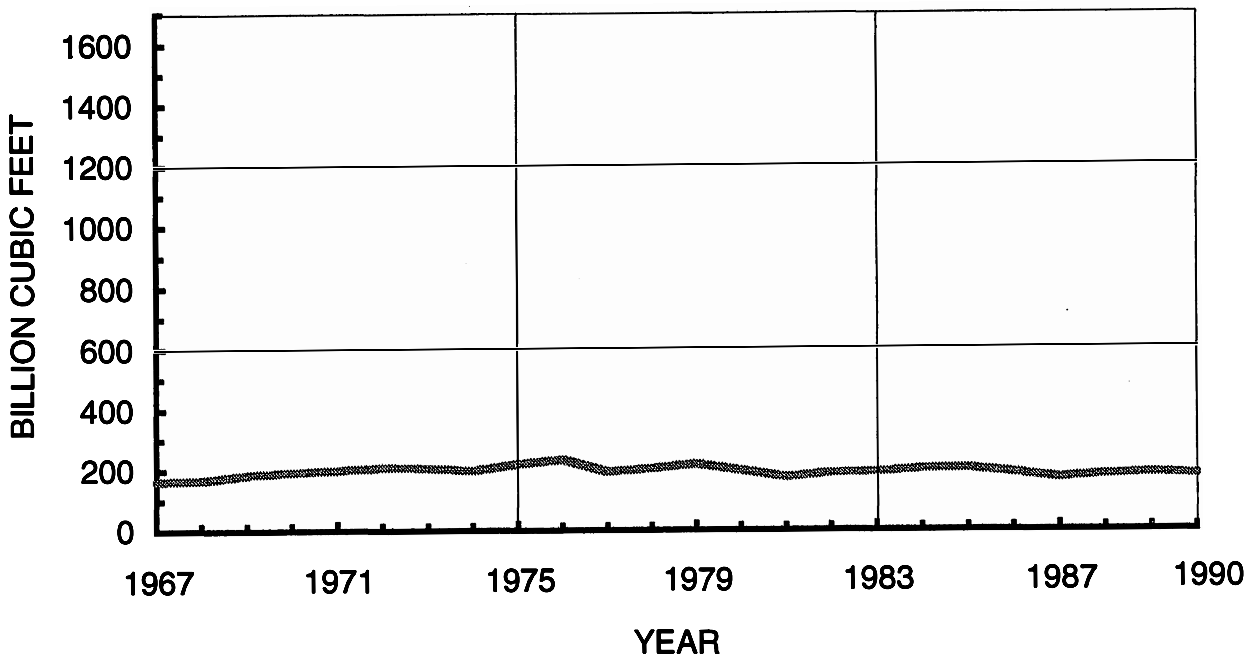
Region Six
Total Consumption.



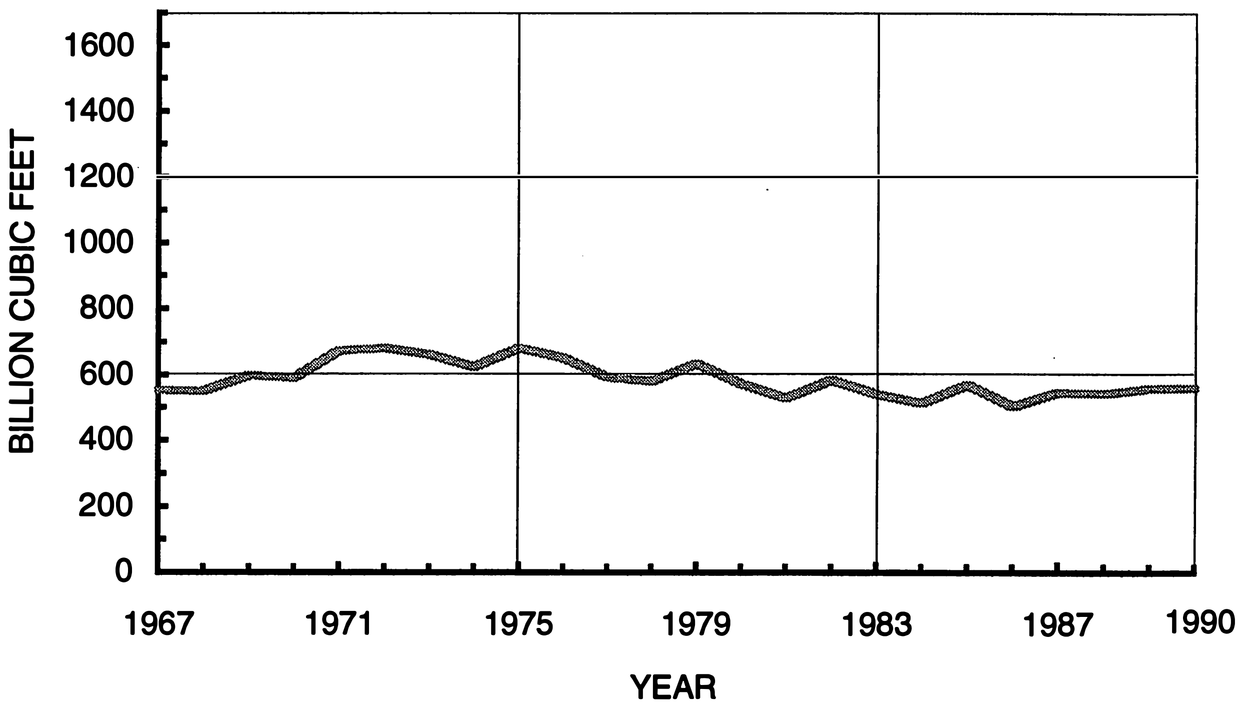
Region Seven
Total Consumption.



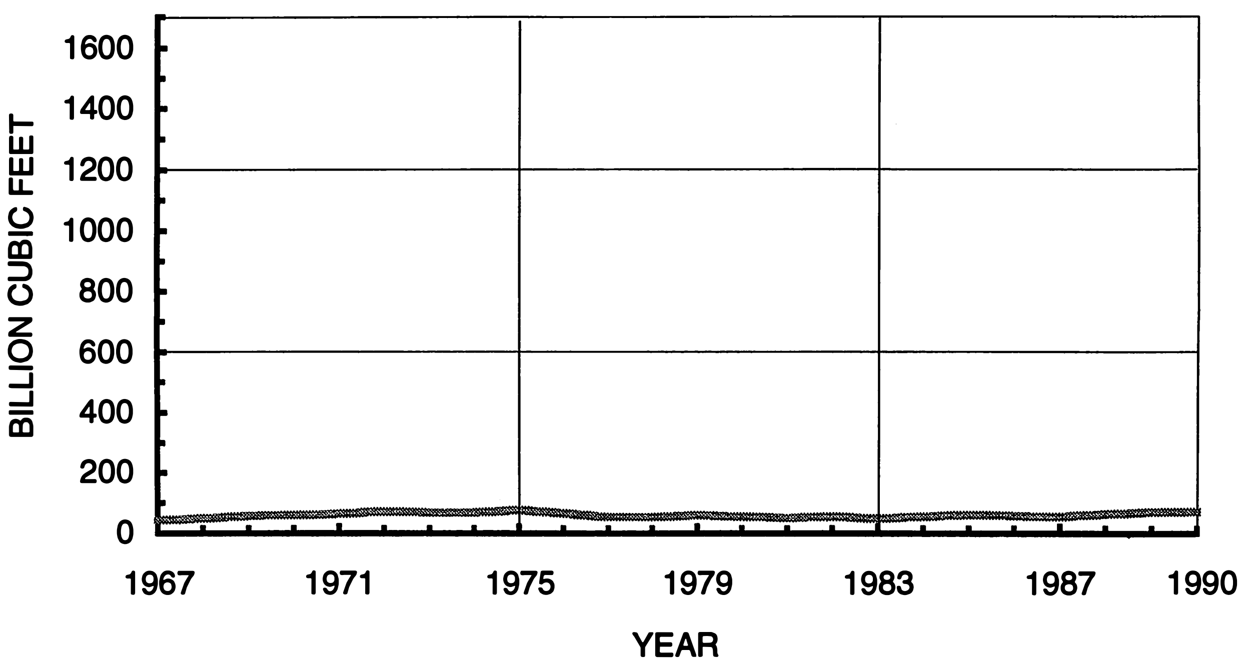
Region Eight
Total Consumption.



Region Nine
Total Consumption.



Region Ten
Total Consumption.

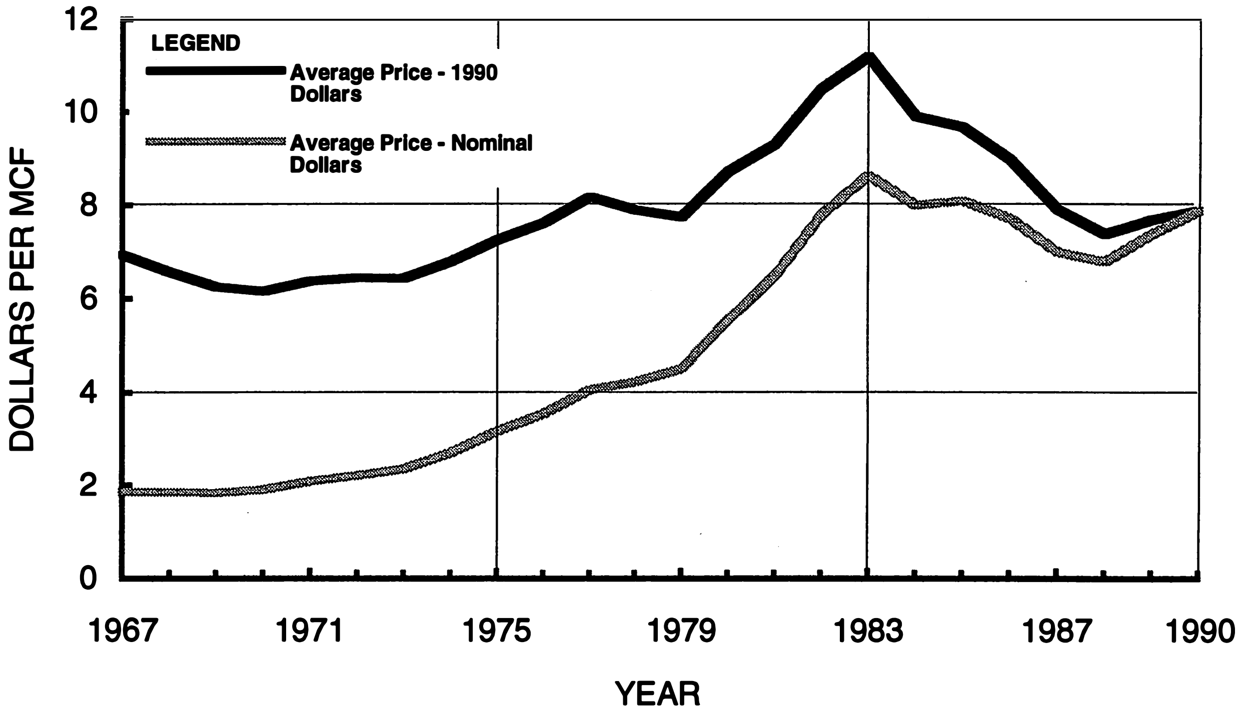


Average Price

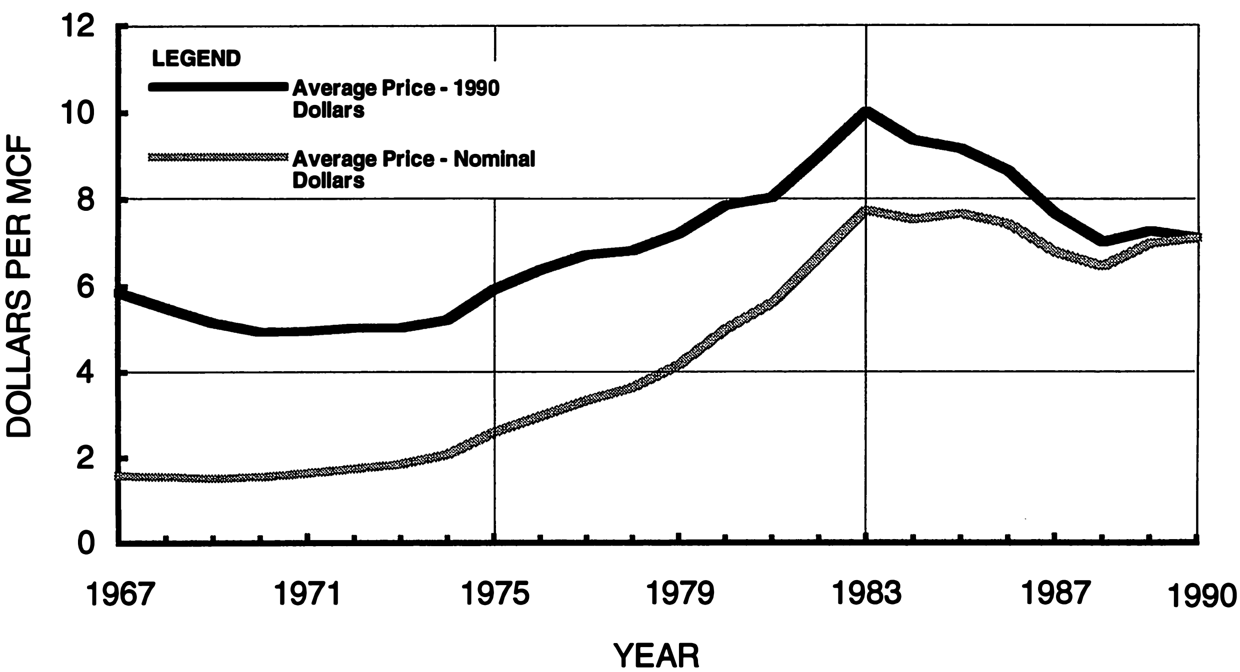
Regions 1-10

Region One:	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont
Region Two:	New York and New Jersey
Region Three:	Delaware, Pennsylvania, Maryland, Virginia, West Virginia, and District of Columbia
Region Four:	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee
Region Five:	Illinois, Indiana, Michigan, Ohio, Wisconsin, and Minnesota
Region Six:	Arkansas, Louisiana, Oklahoma, Texas, and New Mexico
Region Seven:	Iowa, Kansas, Missouri, and Nebraska
Region Eight:	Colorado, Utah, Wyoming, Montana, North Dakota, and South Dakota
Region Nine:	California, Arizona, and Nevada
Region Ten:	Idaho, Washington, and Oregon

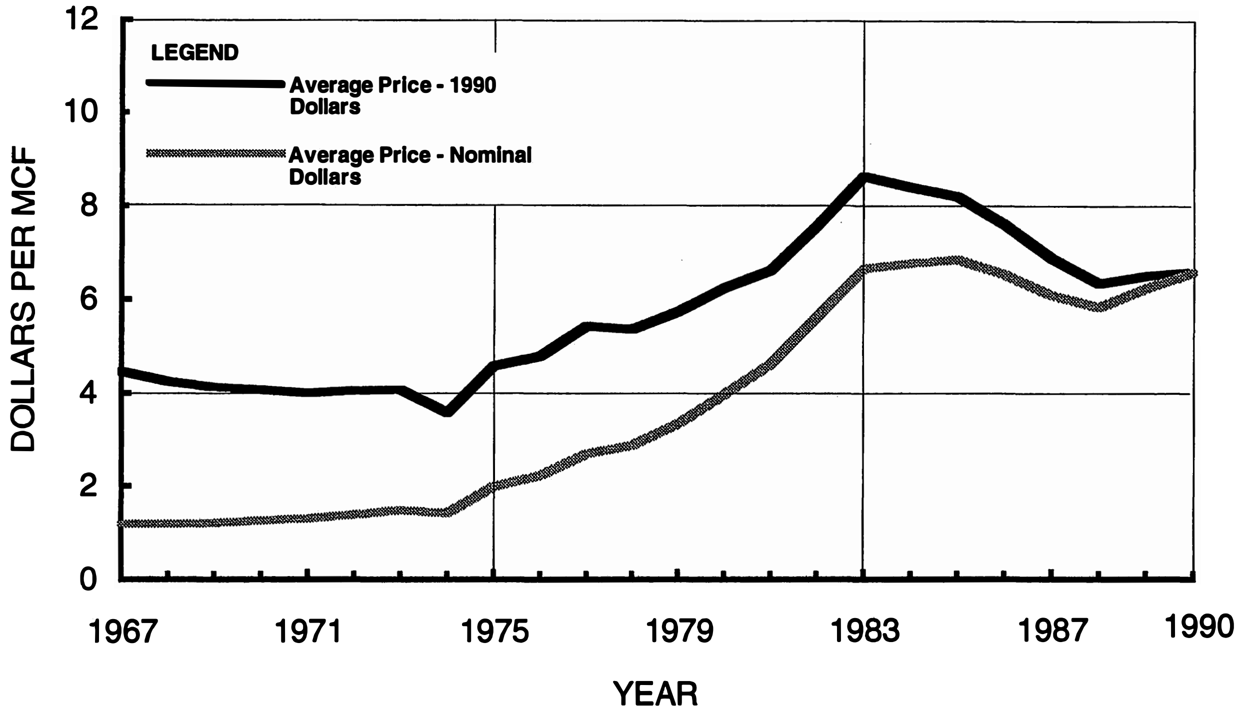
Region One
Average Price Per MCF.



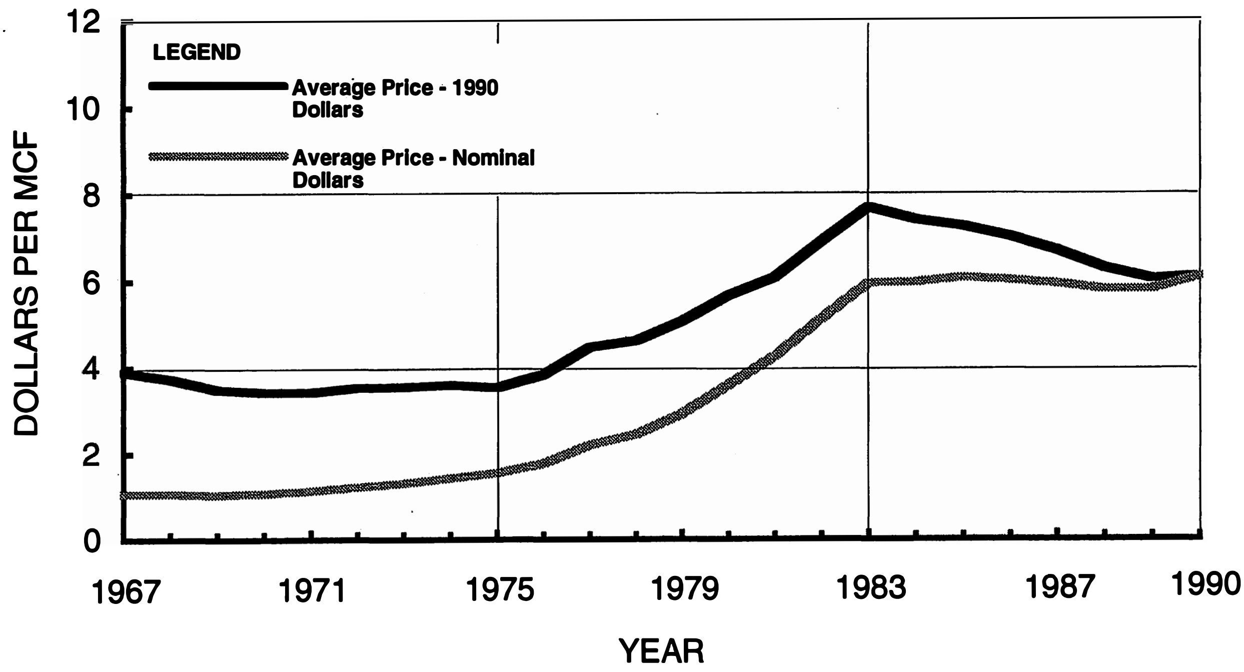
Region Two
Average Price Per MCF.



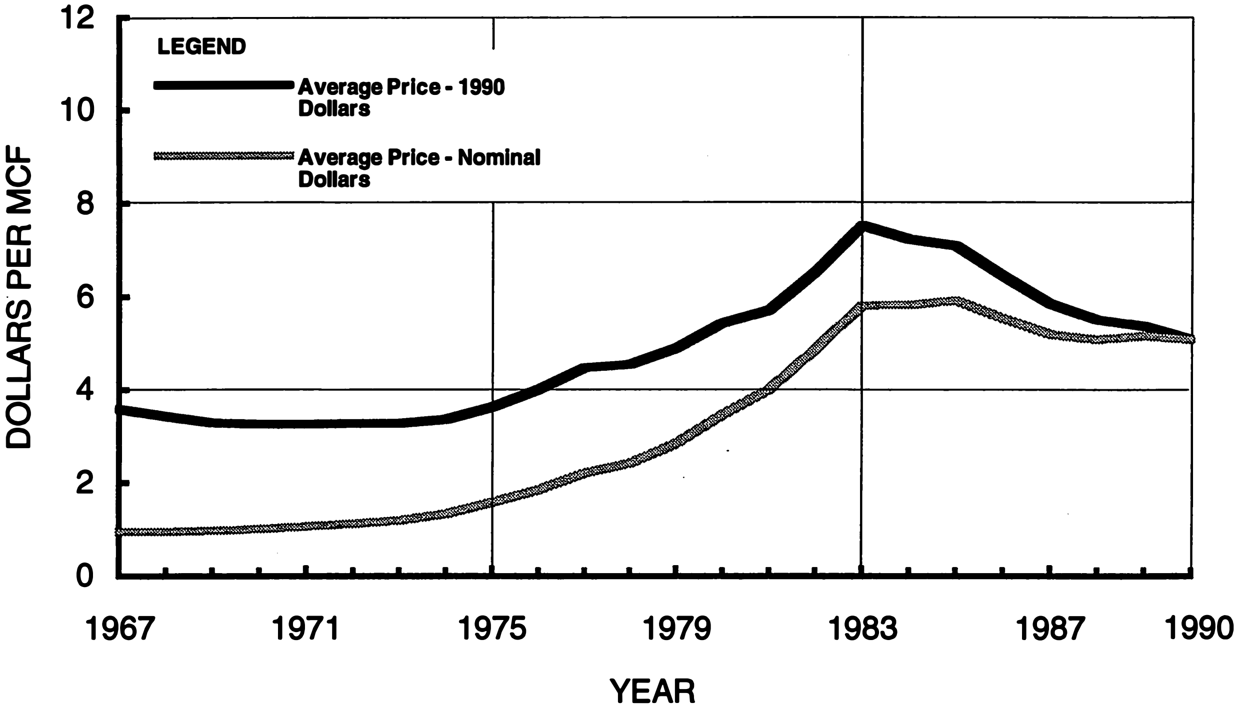
Region Three
Average Price Per MCF.



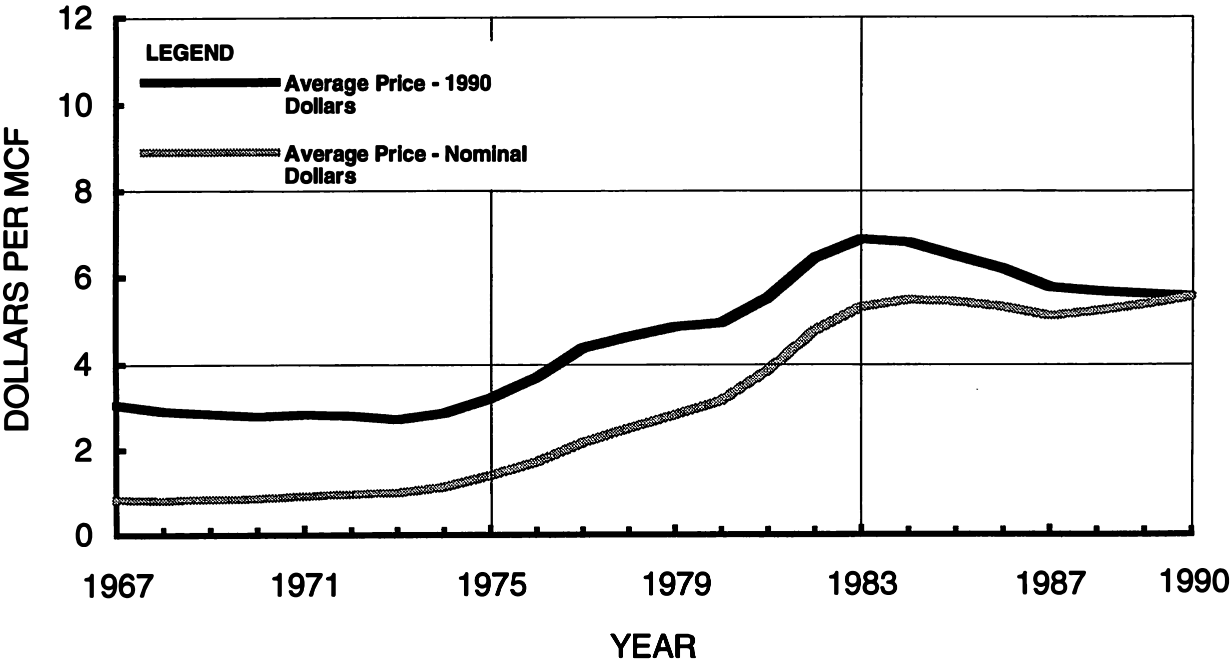
Region Four
Average Price Per MCF.



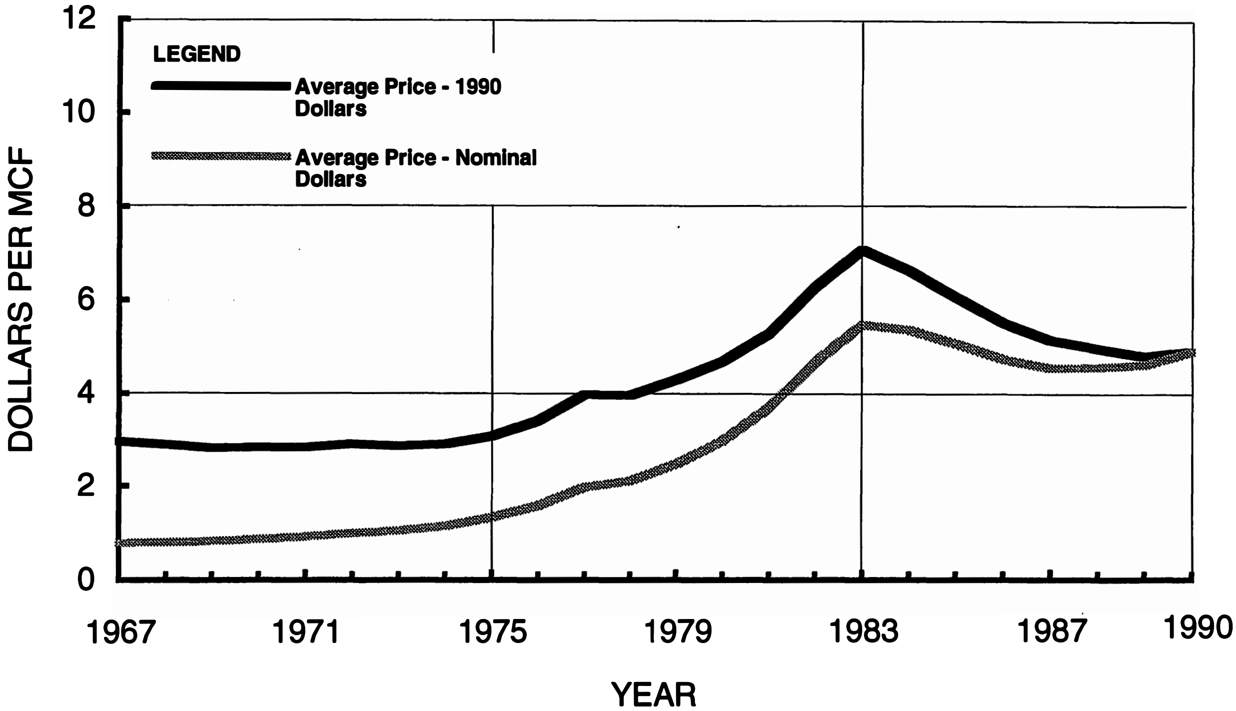
Region Five
Average Price Per MCF.



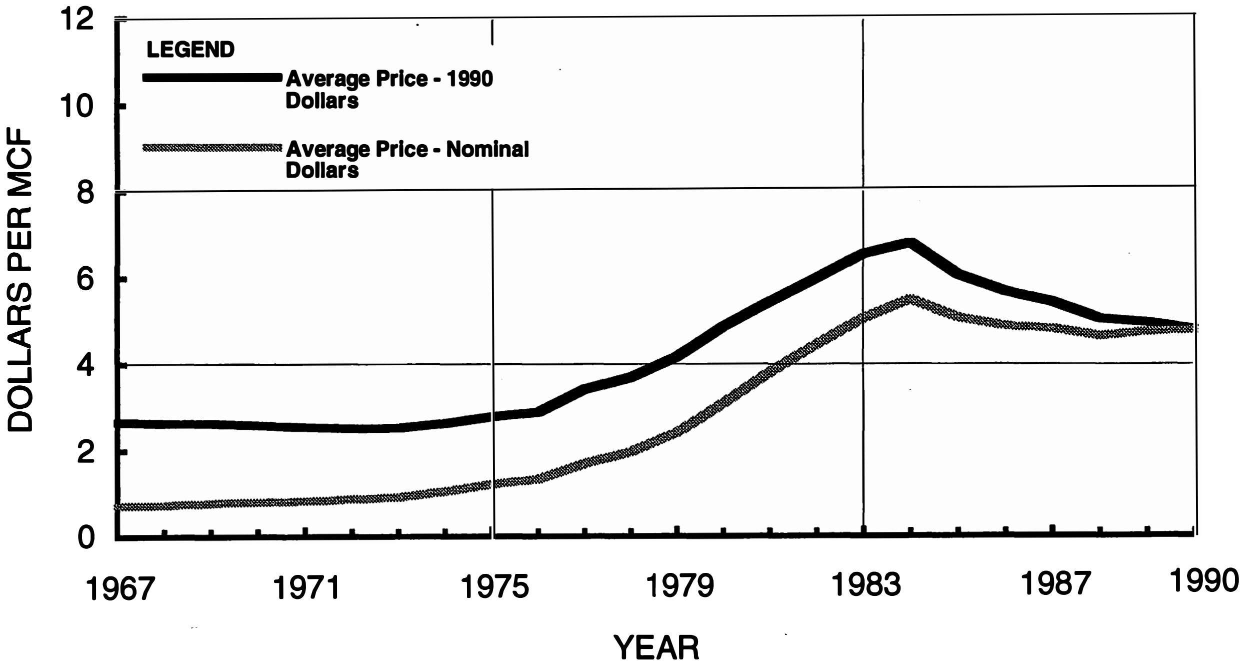
Region Six
Average Price Per MCF.



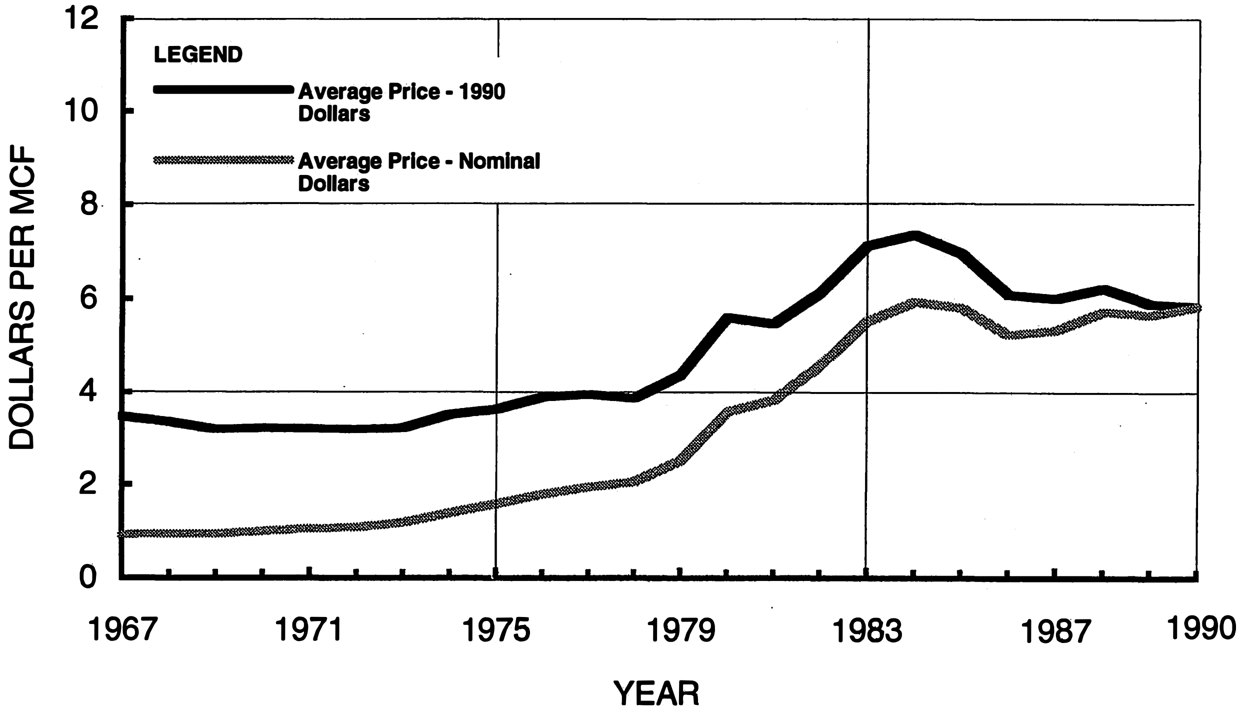
Region Seven
Average Price Per MCF.



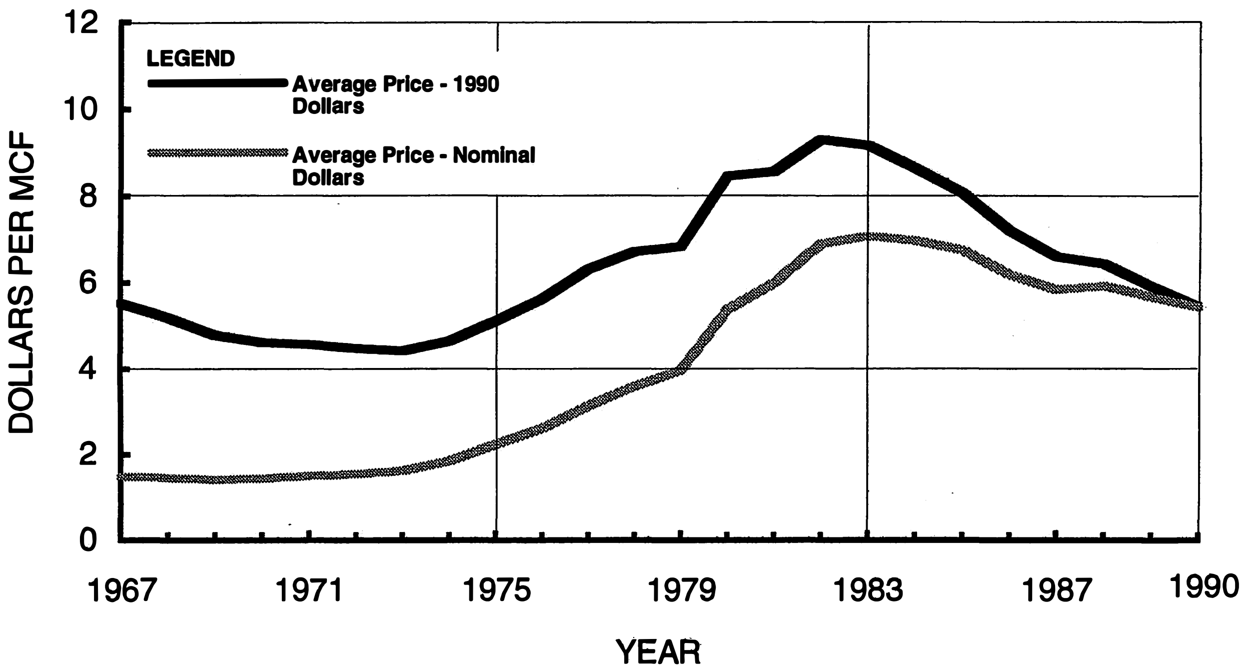
Region Eight
Average Price Per MCF.



Region Nine
Average Price Per MCF.



Region Ten
Average Price Per MCF.



Appendix E
Elasticity Analysis

An elasticity analysis was conducted of the effect of increases in natural gas prices on consumption in real terms. Table E-1 presents the results. The methodology is relatively simple:

- Average U.S. consumption per household was 11 80 Therms/household in 1975. Average residential cost of gas was \$3.50/(1990\$) per MCF per household during the early 1970s.[1]
- The 1990 residential cost of gas in real terms was \$5.76. Three possible price escalation scenarios in real terms were considered: 0 percent, 1 percent, and 2 percent for the next 10 years. Currently available information suggests that many people believe that the 2 percent cost increase is not unrealistic. However, two other cases were run as alternate cases: no real cost increase and 1 percent real cost increase.
- Elasticity as defined by economists is negative percent change in quantity with respect to percent change in price. Elasticities of -.2, -.3, and -.4 were considered. A short run residential elasticity of -.4 would not be unrealistically low; in fact, the literature contains higher elasticities. Stated differently, consumers respond to price increases.
- The projected price in the year 2000, relative to \$3.50 from the 1970s, was used to compute percent change in price; combined with elasticity data, a total of nine projected Therms/household solutions were computed.

In 1990, Therms per household were 874, in comparison to 1180 in 1975. The analysis suggests that further declines to the neighborhood of 700 to 800 are possible over the time frame of 1990-2000.

It is crucial to note that the analysis is dependent on assumptions about price changes and consumer behavior as represented by elasticity. There is not universal agreement on the exact values of elasticities and/or price growth.

The results are presented in Table E-1; some decrease in consumption per household appears to be likely.

[1] Information is obtained from Table 2-3.

TABLE E-1

PROJECTED THERMS PER HOUSEHOLD IN 2000 PERCENT CHANGE N PRICE PER YEAR

Elasticity	0%	1%	2%
-.2	1030	990	940
-.3	950	890	820
-.4	870	790	700

SOURCE: Energy Information Administration. The objective of this exercise is not to project Therms per Household consumption. The objective is to indicate that further decreases in consumption per household are likely.

PRICE PROJECTIONS, 1990-2000

Table E-2 references three scenarios of price escalations.

TABLE E-2

PRICE PROJECTIONS (Real $ per MCF)

	Rate of Price Escalation		
	0%	1%	2%
1990	5.76	5.76	5.76
1991	5.76	5.82	5.88
1992	5.76	5.88	5.99
1993	5.76	5.93	6.11
1994	5.76	5.99	6.23
1995	5.76	6.05	6.36
1996	5.76	6.11	6.49
1997	5.76	6.18	6.62
1998	5.76	6.24	6.75
1999	5.76	6.30	6.88
2000	5.76	6.36	7.02

ELASTICITY ANALYSIS

$3.50 is 1972 price; $7.86 is max price (achieved in 1983); Projected Prices for 2000 are $5.76, $6.36, and $7.02.

$$\text{Elasticity} = \frac{-\%\Delta Q}{\%\Delta \text{Price}}$$

Three Elasticities are assumed: -.2, -.3, and -.4

Four (% Δ Price) are assumed:[2]

a) Change between 1972 and 1983.

b) Change between 1972 and 2000 with 0% after 1990.

c) Change between 1972 and 2000 with 1% after 1990.

d) Change between 1972 and 2000 with 2% after 1990.

For each of the three elasticities and four price changes the elasticity equation may be solved for -% Δ Q, and a consumption per household may be determined.

For 1% price escalation and E = -.4, the result is 793 Therms (rounded to 790 in Table E-1). Actual 1990 consumption in Table 2-3 is denoted as 874 Therms (87.4 MCF). This shows that additional conservation is likely.

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[2] It is assumed that the consumer regards the 1972 price as the expected price for the 1972-77 time period; otherwise, 1975 would be used as base year for these calculations.

APPENDIX F
COMPARING OF CENSUS AND NPC REGIONS

CENSUS DIVISION

NEW ENGLAND
- CONNECTICUT
- MAINE
- MASSACHUSETTS
- NEW HAMPSHIRE
- RHODE ISLAND
- VERMONT

MIDDLE ATLANTIC
- NEW JERSEY
- NEW YORK
- PENNSYLVANIA

SOUTH ATLANTIC
- DELAWARE
- DISTRICT OF COLUMBIA
- MARYLAND
- VIRGINIA
- WEST VIRGINIA
- FLORIDA
- GEORGIA
- NORTH CAROLINA
- SOUTH CAROLINA

EAST SOUTH CENTRAL
- KENTUCKY
- MISSISSIPPI
- ALABAMA
- TENNESSEE

EAST NORTH CENTRAL
- ILLINOIS
- INDIANA
- MICHIGAN
- OHIO
- WISCONSIN

WEST NORTH CENTRAL
- MINNESOTA
- IOWA
- KANSAS
- MISSOURI
- NEBRASKA
- NORTH DAKOTA
- SOUTH DAKOTA

MOUNTAIN
- ARIZONA
- COLORADO
- IDAHO
- MONTANA
- NEVADA
- NEW MEXICO
- UTAH
- WYOMING

PACIFIC
- ALASKA
- CALIFORNIA
- HAWAII
- OREGON
- WASHINGTON

WEST SOUTH CENTRAL
- ARKANSAS
- LOUISIANA
- OKLAHOMA
- TEXAS

NPC REGIONS

REGION 1
- CONNECTICUT
- MAINE
- MASSACHUSETTS
- NEW HAMPSHIRE
- RHODE ISLAND
- VERMONT

REGION 2
- NEW JERSEY
- NEW YORK

REGION 3
- DELAWARE
- DISTRICT OF COLUMBIA
- MARYLAND
- VIRGINIA
- WEST VIRGINIA
- PENNSYLVANIA

REGION 4
- NORTH CAROLINA
- SOUTH CAROLINA
- FLORIDA
- GEORGIA
- KENTUCKY
- MISSISSIPPI
- ALABAMA
- TENNESSEE

REGION 5
- ILLINOIS
- INDIANA
- MICHIGAN
- OHIO
- WISCONSIN
- MINNESOTA

REGION 7
- NEBRASKA
- KANSAS
- IOWA
- MISSOURI

REGION 8
- MONTANA
- WYOMING
- UTAH
- COLORADO
- NORTH DAKOTA
- SOUTH DAKOTA

REGION 9
- NEVADA
- ARIZONA
- CALIFORNIA

REGION 10
- IDAHO
- WASHINGTON
- OREGON

REGION 6
- TEXAS
- OKLAHOMA
- ARKANSAS
- LOUISIANA
- NEW MEXICO

APPENDIX G

COMMERCIAL GAS COOLING TECHNOLOGIES AND OTHER ADVANCED SYSTEMS

Advanced Absorption Systems: Research projects currently being conducted on advanced absorption systems are the development of the triple-effect absorption chiller and the advanced absorption working fluid/additives. The triple system provides a higher cooling efficiency by the effective utilization of internal heat.

Absorption Chillers: (coefficient of performance-COP range of 0.95-1.18): These systems most often have two-stage or double-effect cycle capabilities in which refrigerant is processed twice to provide more efficient cooling than single-stage equipment. The refrigerant is usually water not chlorofluorocarbons (CFCs). They are commonly found in large commercial buildings that use central cooling plants. (Equipment costs: $375-$1,300/ton; Equipment sizes: 20-1,500 tons).

Engine-Driven Chillers: (COP range of 1.4-2.0): This equipment uses a natural gas engine to drive a refrigerant compressor. The refrigerant is a hydrochlorofluorocarbon (HCFC) which has a lower ozone depletion factor. Engine-driven chillers are generally considered the most efficient of all gas-powered air conditioning technologies. Key to the engine's superior performance is its ability to operate more efficiently than electric systems at part load. (Equipment costs: $45-$850/ton; Equipment sizes: 30-460 tons).

- Direct Expansion (D/X-COP of 0.77): This is a gas rooftop heating and air conditioning system equipped with solid state temperature controls designed for buildings in the 6,000 square foot and larger category. The unit features natural gas heating with gas engine-driven direct expansion cooling. The compressor-drive engine is a 4-cylinder industrial duty type powered by natural gas. The engine also drives the condenser fan. The compressor is a 4-cylinder reciprocating open-drive type using HCFC-22 as the refrigerant. The supply air blowers are powered by an electric motor. The natural gas furnace is an induced draft type with an intermittent pilot ignition system. (Equipment costs: $780-$1,170/ton; Equipment sizes: 15-25 tons).

Desiccant Systems: (COP range of 0.7-1.5): Desiccant Systems lower humidity and can be run in conjunction with another cooling system within a building. Desiccant systems are typically used in operations where high latent cooling loads require full ventilation and strict humidity control. These systems are attractive because they separate the latent loads from the sensible loads to assure adequate moisture removal without overcooling or reheating. The desiccant material can be either in a solid or liquid form. Prime applications are supermarkets, restaurants, health clubs, dry cleaners, motels/hotels, and office buildings. (Equipment costs: $700-$1,300/ton; Equipment sizes: 40-80 tons).

Stirling Engine and IC Engine-Driven Heat Pumps: The Stirling engine operates by compressing and expanding working gas such as helium and hydrogen by heating and cooling. The gas is contained in a continuous closed volume. The closed volume is divided into hot and cold regions. Heating and cooling are accomplished by periodically transferring a working gas between hot/cold regions.

The Stirling engine is a closed cycle device. Internal combustion engines are an open cycle device. The incoming fuel is expanded by combustion and is exhausted. The hot and cold regions of the engine are separated by a transition zone or regenerator region that reduces thermal energy losses. The Stirling engine can operate at a higher efficiency than internal combustion (IC) engines. The combustion of fuel takes place in an external heater. The exhaust gas is cleaner than IC engines, particularly NOx.

Stirling engine heat pump development has been conducted by several companies such as Mechanical Technology Inc. (MTI), Sun Power, and Stirling Power. Demonstration units have been built and show excellent results on emission and efficiency. However, the cost of Stirling engines is considerably higher than IC engines. Main R&D efforts are focused on materials so that engine cost can be reduced.

IC engine heat pumps have been marketed in Japan for about five years. In the U.S., the York 3-ton gas engine heat pump is ready for market evaluation. Fifty units will be sold and installed by York distributors nationally. The target for installed cost is $6,500 which is equivalent to high efficiency variable speed heat pumps. The full commercialization of the gas-engine heat pump will be in late 1994. It is expected that the installed cost of high-efficiency electric heat pumps will be down to about $5,500 by 1994. The cost of the gas-engine heat pump must be reduced to meet competition.

Desiccant Cooling Systems: The desiccant cooling system operates by reducing air humidity by desiccant materials such as silica gels. The moisture in the desiccant material is removed by heating with the heated air. The dried air goes through a evaporative cooler to reduce the air temperature. Desiccant systems are utilized at super market to reduce air humidity and thereby reducing the frosting of freezing devices. By humidifying the air, the air temperature can be maintained at a comfortable level without creating frost. The desiccant system can reduce air conditioning operating costs and can provide comfort to customers.

Cogeneration Systems and Fuel Cells: Cogeneration systems and fuel cells can provide electrical power and thermal energy in the form of hot water or steam. Cogeneration systems utilize natural gas-driven IC engines and gas turbines to drive an electric generator. The thermal energy recovered from the engine cooling system and the engine exhaust gas is used to produce hot water or steam. The exhaust gas from a gas turbine is often used to run direct-fired gas absorption chillers.

Smaller cogeneration systems are designed for thermal demand. Thermal demand drops to a preset level, the cogeneration system is turned off, and the utility power is used. The preset level is determined by economic conditions. The economy of cogeneration systems depends on the installed-cost of a cogeneration system and local electric rates.

In fuel cell devices, the chemical reaction of hydrogen and oxygen within an electrolyte creates electricity and water. Chemical reaction also produces heat which is recovered in terms of hot water or steam. Hydrogen is derived from methane and oxygen is taken from the air.

Fuel cell devices are classified by type of electrolyte used. Phosphoric acid fuel cell operates at a lower temperature in a range of 180-250°F. The 200 kw phosphoric fuel cell is available commercially from International Fuel Cell Corporation (IFC). So far only 55 units have been sold at a cost of $500,000 per unit.

Condensing Furnace: If a gas furnace operates under a condition such as when the exhaust gas temperature is the same as the room delivery temperature, the efficiency of a gas furnace is 100 percent. It is impossible to operate a gas furnace under such condition. Heat cannot be transferred if the temperature of two mediums is the same. The highest efficiency that can be obtained is when the flue gas temperature is reduced to about 140 degrees at which time the moisture in the flue gas is condensed and latent heat is recovered. The efficiency of a condensed gas furnace is between 94 and 97 percent.

Since the flue gas temperature is about 140°F, PVC pipe can be used for venting. If a power-vented water heater is also used, a house can be built without a chimney. The current National Appliance Conservation Act (NAECA) allows users to use mid-efficiency and condensing gas furnaces only—except for the Lennox Whisperheat gas furnace. It is possible that the second cycle of the NAECA standard for gas furnaces (which will be decided in 1994) may eliminate mid-efficiency gas furnaces.

Two-psig Systems and Corrugated Stainless Steel Tubing (CSST): The 2-psig gas pressure allows the use of much smaller gas tubing to carry the same volume of gas. The use of smaller diameter semi-ridged copper tubing or CSST can reduce installation-time and in many cases the installed-cost. The CSST was adopted by the National Fire Protection Association (NFPA) and accepted by many national code organizations such as Building Officials & Code Administrators International, Inc. (BOCA). More than two-thirds of the country allow the use of CSST.

Boiler Use in High-Rise Buildings: The distribution of hot water or steam is more efficient when compared to the forced-air system for a high-rise building. If the heat delivery to each tenant is measured individually, a BTU meter must be utilized. The accuracy of a BTU meter can be off by as much as ten percent. It is necessary to develop more efficient and low-cost BTU meters. GRI is funding a BTU meter development project.

Gas Cooling Equipment Manufacturers:

Absorption Systems	Direct Expansion
American Yazaki Corp.	Thermo King Corp.
Carrier Corporation	
Snyder General Co.	
The Trane Company	
York International Co.	

ADVANCES IN RESTAURANT EQUIPMENT

Lang Clamshell Griddle Base with Gas Broiler Hood: This unit cooks from both sides by incorporating a griddle with an infrared hood. The hood's 35,000 BTU infrared burner, heats up to 1,600 degrees automatically when lowered. A Clamshell griddle can increase kitchen productivity per square foot of floor space; a 3 foot clamshell unit has the same production capabilities as a 5 foot griddle or broiler. The Clamshell is available in 2-3-4 foot configurations with or without grooved surfaces.

Bakbar Appliances G32 Countertop IR Convection Oven: The first countertop unit to use a gas infrared burner, it has a patented tube-ray infrared burner system rated at 33,000 BTUs per hour. The air, which is drawn from under the cabinet, is pre- heated and passed into the infrared combustion chamber. From there it is ducted to the rear of the oven-side fan and circulated into the oven. The oven is designed with "swirl" barrel shaped walls and rounded corners that slow the air flow for more even baking capability. This unit is currently undergoing AGA laboratory certification and should be available this summer.

Wolf Range IR Jet Burner: This infrared rangetop burner improves fuel use efficiently nearly 50 percent and reduces kitchen heat gain. The burner produces instant heat and requires only 14,500 BTUs per hour versus that of a standard 20,000 BTU range burner. The burner is currently in field test and product introduction is anticipated in the fall/winter 1992.

Wolf Range Two-Sided Cooker: A double-sided griddle which offers high production capabilities, juicier and tastier product, also reduces product shrinkage. This unit is being tested in selected western markets.

Maxi-Grill Double-Sided Cooking Appliance: This high volume output revolving grill with a canopy infra-red broiling unit mounted above can produce up to 1,400 patties per hour by cooking both sides of food product simultaneously. This unit was designed for fast food operations.

Vanguard Technology Booster Water Heater: This gas booster water heater supplies 185 degree sanitizing rinse water for warewashing (125,000 and 250,000 BTU packages). This pre-assembled system is space-saving, modular and easy to install. It can be located up to 50 feet away from the dishwashing area.

Cleveland Range KGL-40 Steam Jacketed Kettle: Kettle uses high-efficiency (62 percent) burner heating system for fast heat-up and recovery. It delivers consistent temperatures due to automatic ignition system and solid state controls. This unit is available in 40 to 80 gallons with rating from 140,000-190,000 BTUs per hour.

Cleveland Combicraft Combination Convection Steamer/Oven: Steamer/oven offers pressureless cooking in a variety of models. There's hot air convection, hot air convection with water injection for high moisture, convection steam and low temperature convection steam and combination cooking mode combining convected hot air and steam for faster cook time and juicy product. Unit offers "cook 'n hold" and a programmable memory.

Pitco Technofry 1 RPB 14 (Radiant Power Burner) High Efficiency Fryer: System offers 2 metal fiber radiant power burners for high production, each rated at 40,000 BTUs per hour. Unit recirculates hot combustion gases around the side and front of the tank for greater heat transfer to the shortening. Use of power burners and design greatly reduces recovery time between loads. Positive cooling zone traps burnt particles, crumbs, and other particles which prevents shortening breakdown and taste transfer.

Smokeless Broiler: The design of this unit incorporates a trickle of water which flows across the base or "grease" pan. The trickle maintains the pans temperature between 130 and 150 degrees which prevents baked on product and grease flare-ups. Less airborne particles decreases maintenance on the ventilation system.

Groen Hypersteam Dual Compartment/Dual Generator Steamer: The steamer features Hy-Perduction for high performance and reliability and has two atmospheric steam generators (rated 45,000 BTU per hour), one for each 3-pan cavity. The system offers speedy start-up, a deliming indicator and automatic boiler blow-down for reduced sediment buildup.

Groen Combo Combination Convection Oven/Steamer: The combo bakes, roasts, steams, broils and more in a variety of cooking modes. Cooking times are reduced considerably. It uses a tube-fired heat exchanger that delivers 10,000 BTUs per hour per pan. It takes less energy to pre-heat, idle, and cook full loads. Available in half and full sizes.

Garland Power Burner Range: This range offers two power burners and two atmospheric burners. Each burner is rated at 20,000 BTUs. The Power Burner pre-mixes air and gas in a forced combustion process that delivers high intensity heat. The range is excellent for sauteing or boiling stock quickly.

Thermo King 15-Ton Cooling Unit: This split coil 15-ton DX gas air conditioner is excellent for fast food operation retrofits requiring smaller tonnage and where heating and air handler components are located elsewhere. 15-ton packaged unitary systems are also available.

Raypak Booster Water Heater: This gas booster water heater, featured in the AGA booth, fits neatly under the counter and is a perfect replacement size for a 40 kwh electric booster heater. This unit provides instant hot water on demand for warewashing needs; offers an energy efficiency of 80 percent, 130,000 BTU per hour input power burner and low operating cost. Venting may be into the steam hood, through-the-wall or directly into the kitchen (pending code).

Also displayed on a panel was a medley of auxiliary equipment such as gas lights, fireplace logs and other pieces of equipment that can be used to enhance the ambiance in restaurants.

Franklin Products 6/13 Convection Oven: The manufacturer states that this unit is unique in that its interior space can accommodate six racks of product in 13 positions without using additional floor space making it a more productive unit than the standard convection ovens on the market. The deep cavity adds to the volume of product able to be produced. Solid state controls and 40,000 BTU input.

Keating of Chicago remains successful with their pasta cooker and just recently introduced a double-sided gas griddle with an electric top. There are no announced plans to offer a gas top for this unit. Keating's new high efficiency gas fryer was featured at their booth although it is only in development stages. This fryer will use two ceramic fiber burners (each rated at 45,000 BTUs) developed by Solaronics.

ACRONYMS AND ABBREVIATIONS

ACE adjusted current earnings

AFUE Average Fuel Utilization Efficiency

AGA American Gas Association

AGCC American Gas Cooling Center

AGS Alberta Geological Society

AMT Alternative Minimum Tax

ANGTS Alaskan Natural Gas Transportation System

ANWR Arctic National Wildlife Refuge

API American Petroleum Institute

ATEPD Alternative Tax Energy Preference Deductions

BCF billion cubic feet

BCF/D billion cubic feet per day

BCM billion cubic meters

B/D barrels per day

BLM Bureau of Land Management

BOE barrels of oil equivalent

BTU British thermal units

CAA Clean Air Act of 1967

CAAA Clean Air Act Amendments of 1990

CERCLA Comprehensive Environmental Response, Compensation and Liability Act of 1980

CERI Canadian Energy Research Institute

CFC chlorofluorocarbons

CLEV California Low Emission Vehicle Regulations

CNG compressed natural gas

CNR Columbia Natural Resources

CO_2 carbon dioxide

COPAS Council of Petroleum Accounting Societies

CWA Clean Water Act of 1977

D&C drilling and completion (costs)

DCF Discounted Cash Flow

DFI Decision Focus Inc.

DOE U.S. Department of Energy

DOI U.S. Department of the Interior

DRI Data Resources Incorporated

DSM Demand Side Management

E&P	exploration and production (costs)
EEA	Energy and Environmental Analysis, Incorporated
EEI	Edison Electric Institute
EIA	Energy Information Administration
EMF	Electric and Magnetic Field
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ERCB	Alberta Energy Resources Conservation Board
ERM	Enhanced Recovery Module of the Hydrocarbon Model
EUR	estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
FRB Index	Federal Reserves Boards' Index of Total Industrial Production
G&G	geological and geophysical (expenditures)
GATT	General Agreement on Tariffs and Trade
GEMS	Generalized Equilbrium Modeling System
GRI	Gas Research Institute
HDD	heating degree days
HSM	Hydrocarbon Supply Model
HVAC	Heating, Ventilating, and Air Conditioning
IDC	Intangible Drilling Costs
IEA	International Energy Agency
IGTCC	Industrial Gas Technology Commercialization Center
INGAA	Interstate Natural Gas Association of America
IOGCC	Interstate Oil and Gas Compact Commission
IPAA	Independent Petroleum Association of America
IPP	independent power producer
IRP	integrated resource planning
JAS	Joint Association Survey
KW	kilowatts
KWH	kilowatt hours
LAER	lowest achievable emission rate (controls)
LCP	least cost planning
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MAFLA	Mississippi, Alabama, Florida onshore
MCF	thousand cubic feet
MCF/D	thousand cubic feet per day
MECS	Manufacturing Energy Consumption Survey
MMBTU	million British thermal units
MMCF	million cubic feet
MMCF/D	million cubic feet per day
MMS	Minerals Management Service, Department of Interior

MOPPS (I&II)	Market Oriented Program Planning Study
MPRSA	Marine Protection, Research and Sanctuaries Act, 1972
MW	megawatts
MWH	megawatt hours
NAAQS	National Ambient Air Quality Standards
NAECA	National Appliance Energy Conservation Act
NAFTA	North American Free Trade Agreement
NARG	North American Regional Gas Model
NARUC	National Association of Regulatory Utility Commissioners
NEB	National Energy Board of Canada
NEPA	National Environmental Policy Act of 1969
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NES	National Energy Strategy
NGA	Natural Gas Act of 1938
NGL	natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGSA	Natural Gas Supply Association
NGV	Natural Gas Vehicle
NGVC	Natural Gas Vehicle Coalition
NGWDA	Natural Gas Wellhead Decontrol Act of 1989
NIMBY	Not In My Back Yard
NMS	National Marine Sanctuary Program
NORM	naturally occurring radioactive material
NOx	nitrogen oxides
NPC	National Petroleum Council
NPDES	National Pollutant Discharge Elimination System
NRRI	National Regulatory Research Institute
NUG	non-utility generator
NYGAS	New York State Gas Association
O&M	operating and maintenance (expenses)
OCS	Outer Continental Shelf
OGIFF	Oil and Gas Integrated Field File
OPA	Oil Pollution Act of 1990
OPEC	Organization of Petroleum Exporting Countries
PEMEX	Petroleos Mexicanos, national oil company of Mexico
PGC	Potential Gas Committee of the Colorado School of Mines
PIFUA	Powerplant and Industrial Fuel Use Act of 1978
PMA	Federal Power Marketing Agencies
PSC	Public Service Commission
PUC	Public Utility Commission
PUCHA	Public Utilities Holding Company Act
QBTU	quadrillion British thermal units
RACC	Refiners Acquisition Cost of Crude Oil

RCRA	Resource Conservation and Recovery Act of 1976
R&D	research and development
RD&D	research, development, and demonstration
RECS	Residential Energy Consumption Survey
ROR	rate of return
SARA	Superfund Amendments and Reauthorization Act of 1986
SCF	standard cubic feet
SDWA	Safe Drinking Water Act of 1984
SEC	Securities and Exchange Commission
SEDS	State Energy Data System
SFV	straight fixed variable
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SMP	special marketing program
SO_2	sulfur dioxide
SOx	sulfur oxides
SPP	small power producer
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TBTU	trillion British thermal units
TCF	trillion cubic feet
TRC	Texas Railroad Commission
TSCA	Toxic Substance Control Act of 1976
UDI	Utility Data Institute
UIC	Underground Injection Control program
USGS	United States Geological Survey
VOC	volatile organic compounds
WCSB	Western Canada Sedimentary Basin

Glossary

Abandonment
When an interstate pipeline closes facilities, stops transporting gas in interstate commerce, or stops sales of gas for resale with permission of the Federal Energy Regulatory Commission.

Alaska Natural Gas Transportation (ANGTS)
A proposed pipeline to transport gas from Prudhoe Bay, Alaska, to the lower-48 states. Portions of the line were "prebuilt" prior to the flow of Alaskan gas, with the rest of the system awaiting sponsors and economically viable gas prices.

Allowable
The maximum amount of gas a specific field, lease, or well is permitted to produce.

Alternative Minimum Tax (AMT)
Under the Tax Reform Act of 1986 the minimum tax was reformulated as the AMT and expanded to the point where it became the *de facto* corporate income tax for many capital-intensive firms. The AMT is imposed at 20 percent rate (24 percent non-corporate) on a broader income than that used for regular income tax, and the taxpayer pays the higher of the two taxes.

American Gas Association (AGA)
The gas utility industry trade association.

Antrim Shale
The Antrim shale is a formation of primarily Devonian age located in the Michigan Basin.

Associated Dissolved Gas
The combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Back Haul
A contractual form of natural gas transportation service, where natural gas is delivered to the shipper at a point on the pipeline system which is upstream of the point where gas is received into the system. Contractually, the natural gas is transported against the direction of natural gas flowing in the pipeline system. In most cases this type of service can be provided without the need to construct new facilities, and in operation may actually reduce the variable costs (fuel) incurred by the pipeline to provide transportation service. It also has the effect of increasing the effective capacity of the pipeline system.

Base Gas
(*See* Cushion Gas.)

Base Load Generating Unit
Those generating units at electric utilities that are normally operated to meet electricity demand on a round-the-clock basis.

Base Rate

That portion of the total electric rate which covers the general costs of doing business unrelated to fuel expenses.

BCF

Billion Cubic Feet. A volumetric unit of measurement for natural gas.

Blanket Certificate (Authority)

Permission granted by the Federal Energy Regulatory Commission (FERC) for a certificate holder to engage in an activity (such as transportation service or sales) on a self-implementing or prior-notice basis, as appropriate, without case-by-case approval from the FERC.

British Thermal Unit (BTU)

A standard unit for measuring the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit at or near 39.2 degrees Fahrenheit.

Capacity Brokering

A process where an existing natural gas shipper sells or leases its contractual capacity rights to transport natural gas on a pipeline to someone else.

Certificated Capacity

The maximum volume of gas that may be stored in an underground storage facility certificated by the Federal Energy Regulatory Commission or its predecessor, the Federal Power Commission. Absent a certificate, a reservoir's present developed operating capacity is considered to be its "certified" capacity.

Certificates of Public Convenience and Necessity

Certificates required under the Natural Gas Act and issued by the Federal Power Commission/Federal Energy Regulatory Commission prior to construction or expansion of an interstate pipeline; after the pipeline showed the existence of market demand and attendant gas supply.

Christmas Tree

The valves and fittings installed at the top of a gas well to control and direct the flow of well liquids.

Citygate

A point or measuring station at which a gas distribution company receives gas from a pipeline company or transmission system.

Citygate Sales Service

Interstate pipeline natural gas sales service where the title to gas sold changes at the pipeline's interconnection with the purchasing local distribution company.

Coal Gasification

The process of placing coal steam and oxygen under pressure to produce gas.

Cofiring (reburning)

The process of burning natural gas in conjunction with another fuel to reduce air pollutants and/or take advantage of lowest available fuel prices.

Cogeneration

The sequential production of electricity and another form of useful thermal energy such as heat or steam and used for industrial, commercial heating or cooling purposes. There are basically three types; boiler steam turbine, combustion turbine with waste heat recovery steam generator, and combined cycle.

Coke Oven Gas

The gaseous portion of volatile substance driven off in the coking process after other coal chemicals are removed.

Combined Cycle

An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Commercial Consumption

Gas consumed by nonmanufacturing establishments or agencies primarily engaged in the sale of goods or services. Included are such establishments as hotels, restaurants, wholesale and retail stores, and other service enterprises; gas consumed by establishments engaged in agriculture, forestry, and fishers; and gas consumed by local, state, and federal agencies engaged in nonmanufacturing activities.

Conventional Resources

Resources included in this category are crude oil, natural gas, and natural gas liquids that exist in reservoirs in a fluid state amenable to extraction employed in traditional development practices. They occur as discrete accumulations. They do not include resources occurring within extremely viscous and intractable heavy oil deposits, tar deposits, oil shales, coalbed gas, gas in geopressured shales and brines, or gas hydrates. Gas from low-permeability "tight" sandstone and fractured shale reservoirs having in situ permeability to gas of less than 0.1 millidarcy are not included as conventional resources.

Cost-of-Service Rates

A method of rate making used by utilities under which the original cost of facilities are depreciated for an expected life, and the annual costs and the operating and maintenance costs are allocated to each service offered according to a test year and projected volumes.

Cross Subsidies

Subsidies among customers or customer classes so that one group carries a disproportionate share of the costs of providing service.

Curtailments

The rationing of natural gas supplies to an end user when gas is in short supply, or when demand for service exceeds a pipeline's capacity, usually to an industrial user and/or power generator.

Cushion Gas

The volume of gas, including native gas, that must remain in the storage field to maintain adequate reservoir pressure and deliverability rates throughout the withdrawal season.

Cycling

The process of injecting or withdrawing a percentage or all of a reservoir's working gas capacity during a particular season.

Cycling Unit (Intermediate Unit)

Units that operate with rapid load changes, frequent starts and stops, but generally at somewhat lower efficiencies and higher operating costs than base load plants. These units are generally either former base load units regulated to cycling units, or newly built units of a lower megawatt rating which require less capital investment per unit of output than required for base load units.

Decatherm

Ten therms, or 1,000,000 BTU.

Deep Gas Deposits

Deposits of gas below 15,000 feet, where the porosity and permeability are reduced by the deeply buried sediments.

Deliverability

The rate at which gas can be withdrawn from an underground reservoir. Actual rates depend on rock characteristics, reservoir pressure, and facilities such as wells, pipelines, and compressors.

Delivered

The physical transfer of natural, synthetic, and/or supplemental gas from facilities operated by the responding company to facilities operated by others or to consumers.

Demand Charge

A charge levied in a contract between a pipeline and local distribution company, electric generator, or industrial user for firm gas pipeline transportation service. The demand charge must be paid whether or not gas is used up to the volume covered by the charge.

Demand Side Management

Programs designed to encourage customers to use less natural gas or other fuels or less electricity and to use it more efficiently (i.e., conservation) or to reduce peak demand (i.e., load management).

Design Day Capacity

The volume of natural gas that a pipeline facility is designed to transport during one day, given the assumptions used in the design process, such as pressures, pipeline efficiency, and peak hourly rates.

Design Day Deliverability

The rate of delivery at which a storage facility is designed to be used when storage volumes are at their maximum levels.

Developed Operating Capacity

That portion of operating capacity which is currently available for storage use.

Devonian Shale

Any body of shale (a fine-grained, detrital, sedimentary rock with a finely laminated structure) formed from the compaction of clays and/or silts and/or middays that were deposited during the Devonian period of the Paleozoic era, from approximately 400 million to approximately 345 million years before the present.

Displacement

A method of natural gas transportation/delivery that is similar to a back haul (see above). In a displacement service, natural gas is received by a pipeline at one point and delivers equivalent volumes at another point, without necessarily transporting the natural gas in a line between the two points. Displacement service may contain elements of forward haul, back haul, and displacement to effect delivery.

Dry Natural Gas Production

Marketed production less extraction loss.

Electric Generators

Establishments that generate electricity. These include traditional electric utilities; independent power producers; and commercial and industrial establishments that generate electricity for their own use, often using cogeneration facilities, and which may sell some of the electricity to an electric utility for resale. In the NPC report, commercial and industrial generators of electricity are included in the commercial and industrial sectors and all other generators are dealt with under "electric generation."

Electric Utilities

Establishments primarily engaged in the generation, transmission, and/or distribution of electricity for sale or resale.

Electric Utility Consumption

Gas used as fuel in electric utility plants.

End-Use Sector Models

Energy and Environmental Analysis, Inc.'s process-engineering models used in the NPC Gas Study and include the Residential, Commercial, Industrial, and Electric Utility Demand Models.

End User

Anyone who purchases and consumes natural gas.

Energy Overview Model

Energy and Environmental Analysis, Inc.'s forecasting model, which simulates the natural gas supply/demand balance through the use of 3 sets of model components (End-Use Sector Models, the Pipeline Model, and the Hydrocarbon Supply Model) and used in the NPC Gas Study.

Exchange

A method of natural gas transportation/delivery among two (or more) parties. Where one party has a natural gas supply at one point, convenient to one pipeline system, and another party has gas at another point, convenient to another pipeline system, a swap is arranged. The two pipelines do not necessarily have to interconnect. Essential to the concept is that both parties receive mutual benefits. Exchange agreements usually contain some form of balancing mechanism requiring either the delivery of natural gas, in kind, or payment.

Exports

Natural gas deliveries from the continental United States and Alaska to foreign countries.

Externality

A side effect that can create benefits or costs in a transaction and which fall upon those not directly involved in, or who are external to, the transaction.

Extraction Loss

The reduction in volume of natural gas due to the removal of natural gas liquid constituents such as ethane, propane, and butane at natural gas processing plants.

Federal Power Commission (FPC)

The predecessor agency of the FERC, which was created by Congress in 1920 and was charged with regulating the interstate electric power and natural gas industries.

Federal Energy Regulatory Commission (FERC)

A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. Five members are appointed by the President of the United States and, upon confirmation by the Senate, serve fixed terms. This independent agency is administered by the Chairman of the five-person commission. No more than three of the five members may belong to the President's political party.

FERC Order 436

An order issued October 9, 1985, by the FERC, which created a voluntary blanket certificate transportation program. Under this program, participating pipelines were authorized to provide firm and interruptible transportation to any willing shipper without prior case-specific FERC approval. Pipelines providing this service are required to serve on a non-discriminatory basis any shipper willing to meet the terms and conditions of the pipeline's tariff. Participating pipelines were also subject to a requirement that they allow existing firm sales customers to convert their sales service to firm transportation service.

FERC Order 451

Order 451 was issued in 1986 and eliminated old gas "vintaging" pricing, which was based on the date of first production of the gas reserves. The Order established a new ceiling price for all vintages of old gas, which a pipeline purchaser could purchase or release under a procedure called "good faith negotiations."

FERC Order 500

In Associated Gas Distributors vs. FERC, Order 436 was remanded back to FERC. In response, FERC issued Order 500 in August 1987, which restated Order 436 with two major changes: elimination of the customer contract demand reduction option, and creation of a take-or-pay crediting mechanism. This mechanism was designed to affect take-or-pay obligations of interstate pipelines caused by Order 436 transportation.

FERC Order 490

Order 490 was issued in 1988 and established an expedited abandonment procedure for gas under expired or terminated contracts.

FERC Order 636 (*See also* Unbundling)

An order issued April 8, 1992, by the FERC, requiring open-access interstate pipeline companies to unbundle their transportation delivery services from their natural gas sales services. Order 636 also required other changes designed to enhance the access to gas supplies, no matter who owned or sold them, on an equal basis.

Field

A single pool or multiple pools of hydrocarbons grouped on, or related to, a single structural or stratigraphic feature.

Finding Rate

Some measure of "added proved reserves" divided by some measure of either time or the physical or investment effort expended to generate them. There are many different specific formulations in use.

Firm Gas

Gas sold on a continuous and generally long-term contract.

Firm Service

Service offered to customers (regardless of class of service) under schedules or contracts that anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses that permit unexpected interruption in case the supply to residential customers is threatened during an emergency.

Flared

Natural gas burned in flares at the base site or a gas-processing plants.

Fracturing

Improvement of the flow continuity between gas-bearing reservoir rock and the wellbore by erecting fractures which extend the distances into the reservoir.

Fuel Cells

A fuel cell, configured like a battery, combines natural gas and oxygen in an electrochemical reaction that produces electricity, heat, and water (often in the form of steam).

Gas Bubble

Surplus gas deliverability at the wellhead.

Gas Condensate Well

A gas well producing from a gas reservoir containing considerable quantities of liquid hydrocarbons in the pentane and heavier range, generally described as "condensate."

Gas Well

A gas well completed for the production of natural gas from one or more gas zones or reservoirs.

Gathering System

Facilities constructed and operated to receive natural gas from the wellhead and transport, process, compress, and deliver that gas to a pipeline, LDC, or end user. The construction and operation of gathering systems is not a federally regulated business, and in some states is not regulated by the state.

Generating Unit

Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (Electricity)

The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (WH).

Generator

A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity

The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Greenfield

A "new" site for the construction of an electric generation plant; in other words, a location that did not previously have a generation unit.

Greenhouse Effect

The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid-Type System

This term describes a natural gas pipeline company that operates facilities which physically interconnect at numerous points within its service area. Typically such a system receives gas from a variety of sources from both ends of its system and is characterized by gas flows which are difficult to trace in a linear fashion.

Gross Withdrawals

Full well-stream volume, including all natural gas plant liquids and all nonhydrocarbons gases, but excluding lease condensate.

Heating Value

The average number of British thermal units per cubic foot of natural gas as determined from tests of fuel samples.

Hub

A hub is a location where gas sellers and gas purchasers can arrange transactions. The location of the hub can be anywhere multiple supplies, pipelines, or purchasers interconnect. "Market centers" are hubs located near central market areas. "Pooling points" are hubs located near center supply production areas. Physical hubs are found at processing plants, offshore platforms, pipeline interconnects, and storage fields. "Paper" hubs may be located anywhere parties arrange title transfers (changes in ownership) of natural gas.

Hydrates

Gas hydrates are physical combinations of gas and water in which the gas molecules fit into a crystalline structure similar to that of ice. Gas hydrates are considered a speculative source of gas.

Hydrocarbon Supply Model

Energy and Environmental Analysis, Inc.'s model of the U.S. and Canada's potential recoverable resource base. This model seeks to show the impact of technological advancements and exploratory and development drilling activity and was used in the NPC Gas Study.

Imports

Gas receipts into the United States from a foreign country.

In-Place Gas Resource

The total in-place gas is the summation of gas already produced, the technically recoverable resource, and the remaining in-place resource.

Incentive Regulation

An alternative to, or modification of, cost of service regulation, which is used in markets that lack sufficient competition (examples include price caps, zone of reasonableness, bounded rates, sharing of efficiency gains, and incentive rates of return).

Independent Power Producers (IPPs)

Wholesale electricity producers that are unaffiliated with franchised utilities in their area. IPPs do not possess transmission facilities and do not sell power in any retail service territory.

Industrial Consumption

Natural gas consumed by manufacturing and mining establishments for heat, power, and chemical feedstock.

Industrial Consumers

Establishments engaged in a process that creates or changes raw or unfinished materials into another form or product. Generation of electricity, other than by electric utilities is included.

Integrated Resource Plan (IRP)

A plan or process used by utilities to evaluate both supply-side and demand-side measures when seeking to prepare for meeting future energy needs and to do so at lowest total costs. ("Least cost" or "best cost" planning is sometimes used synonymously with integrated resource planning.)

Intermediate Load (Electric System)

The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peak load, or the load over a specified time period.

Interruptible Gas

Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company or pipeline under certain circumstances, as specified in the service contract.

Interruptible Service

A sales volume or pipeline capacity made available to a customer without a guarantee for delivery. "Service on an interruptible basis" means that the capacity used to provide the service is subject to a prior claim by another customer or another class of service (18 CFR 284.9(a)(3)). Gas utilities may curtail service to their customers who have interruptible service contracts to adjust to seasonal shortfalls in supply or transmission plant capacity without incurring a liability.

Interstate Pipeline Company

A company subject to regulation by the Federal Energy Regulatory Commission pursuant to the Natural Gas Act of 1938 because of its construction and/or operation of natural gas pipeline facilities in interstate commerce.

Interstate Natural Gas Association of America (INGAA)

Trade group that represents interstate pipeline companies.

Intrastate Pipeline Company

A company that operates natural gas pipeline facilities which do no cross a state border.

Kilowatt

One thousand watts. (*See* Watt.)

Large Diameter Pipe

High pressure natural gas pipeline is constructed, typically, of steel, in different sizes from one inch, outside diameter (O.D.) to 42 inches. Typically "large diameter pipe" is larger than 20 inches, O.D.

Lease and Plant Fuel

Natural gas used in well, field, and lease operations, (such as gas used in drilling operations, heaters, dehydrators, and field compressors), and as fuel in natural gas processing plants.

Light-Handed Regulation

Regulation characterized by reliance on market forces where they are available to help ensure fair access and stable prices. Generally, under such a scheme, companies are given significant discretion to enter and leave a particular service, and over what rate it charges. While such activities are not "deregulated" in the normal sense of the phrase, regulatory scrutiny is usually generic and compliance oriented, rather than intrusive.

Line Pack

The volume of natural gas contained, in a point of time, within the pipeline. Also, a technique to fill a pipeline to its maximum capacity in anticipation of high demands, or hourly fluctuations in demand.

Liquefied Natural Gas (LNG)

Natural gas that has been reduced to a liquid stage by cooling to -260 degrees Fahrenheit and thus sustains a volume reduction of approximately 600 to 1.

Load (Electric)

The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Local Distribution Company (LDC)

A company that distributes natural gas at retail to individual residential, commercial, and industrial consumers. LDCs are typically granted an exclusive franchise to serve a geographic area by state or local governments, subject to some requirement to provide universal service. Rates and terms and conditions of service are typically (but not always) subject to regulation.

Looping

A method of expanding the capacity of an existing pipeline system by laying new pipeline adjacent to an existing pipeline and connected to the existing system at both ends.

Low Permeability

Gas that occurs in formations with a permeability of less than 0.1 millidarcy.

Manufactured Gas

A gas obtained by destructive distillation of coal, or by the thermal decomposition of oil, or by the reaction of steam passing through a bed of heated coal or coke. Examples are coal gases, coke oven gases, producer gas, blast furnace gas, blue (water) gas, carbureted water gas. BTU content varies widely.

Market Center

A place, located near natural gas market areas, where many gas sellers and gas buyers may arrange to buy/sell natural gas. See "Hub."

Marketed Production

Gross withdrawals less gas consumed for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations.

MCF/D

"Thousand cubic feet of natural gas per day." A volume unit of measurement for natural gas.

Megawatt

One million watts of electric capacity. (*See* Watt.)

Minimum Bill

A distributor's obligation to take or pay for the gas volumes specified in its firm service agreements with the pipeline.

MMBTU

"Million British Thermal Units." A unit of measurement of the heating content, as measured in BTU, of natural gas.

MMCF/D

"Million cubic feet of natural gas per day." A volume unit of measurement for natural gas.

National Energy Board

The agency of the Canadian federal government which regulates international and inter-provincial and natural gas trade with(in) Canada. The "NEB" is the Canadian counterpart to the FERC, and like FERC also regulates electricity.

Native Gas

The gas remaining in a reservoir at the end of a reservoir's producing life. After a reservoir is converted to storage, remaining gas becomes part of the cushion gas volume.

Natural Gas

A gaseous hydrocarbon fuel. Primarily made up of the chemical compound methane, or CH_4. Natural gas is found in underground reservoirs, often in combination with oil, and other hydrocarbon compounds.

Natural Gas, Wet After Lease Separation

The volume of natural gas remaining after removal of lease condensate in lease and/or field separation facilities, if any, and after exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Natural gas liquids may be recovered from volume of natural gas, wet after lease separation, at natural gas processing plants.

Natural Gas Act of 1938

Act passed by Congress which regulates the transportation and sale of natural gas in interstate commerce. This statute is administered by the FERC.

Natural Gas Council

Formed in 1992 through the four major U.S. gas industry trade groups to promote awareness of the potential of natural gas and to develop a unified gas industry.

Natural Gas Policy Act of 1978

An act of Congress which effected the phased decontrol of certain categories of natural gas wellhead prices.

Natural Gas Supply Association

Trade group that represents natural gas producers, whether integrated or small.

Natural Gas Wellhead Decontrol Act of 1989

This Act fully decontrols natural gas wellhead prices effective January 1, 1993.

Netback Price

The price for natural gas the producer receives "at the wellhead" as determined by subtracting the cost of all delivery services from the price received "at the burnertip" for natural gas. In a competitive end-use market, it is presumed that a producer would receive no more than the netback price for its gas.

New Fields

A category of the resource base which represents gas that is yet to be discovered. This category is quantified based on risked assessments attributing geologic similarities from known areas, defined as those resources estimated to exist outside of known fields on the basis of broad geologic knowledge and theory.

No-Notice Transportation Service

A term used in FERC Order 636 to describe firm transportation service equivalent in quality to the delivery service provided as an integral part of traditional firm pipeline natural gas sales services.

Nonconventional Gas

Resource that includes shale gas, coalbed methane, and tight gas as these are in a relatively early stage of technical development.

Nonhydrocarbon Gases

Typical nonhydrocarbon gases that may be present in reservoir natural gas, such as carbon dioxide, helium, hydrogen sulfide, and nitrogen.

NORM

"Naturally Occurring Radioactive Material" in exploration and production operations originates in subsurface oil and gas formations and is typically transported to the surface in produced water, both onshore and offshore.

Off-Peak

Periods of time when natural gas pipeline facilities are typically not flowing natural gas at design capacity.

Offshore Reserves and Production

Unless otherwise indicated, reserves and production that are in either state or federal domains, located seaward of the coastline.

Oil-Equivalent Gas

Gas volume that is expressed in terms of its energy equivalent in barrels of oil (BOE). One BOE equals 5,650 cubic feet of gas.

Open-Access Transportation

Interstate natural gas transportation service, available to any willing, credit-worthy shipper, subject to the availability of capacity, on a non-discriminatory basis. (*See* FERC Order 436).

Operating Capacity

The maximum volume of gas an underground storage field can store. This quantity is limited by such factors as facilities, operational procedure, confinement, and geological and engineering properties.

Outer Continental Shelf (OCS)

The undersea area offshore from the coastline of a continent. This area may stretch for many miles from the coastline and be covered by shallow ocean. The Gulf Coast adjacent to Texas, Louisiana, Mississippi, and Alabama is an OCS area with substantial natural gas fields currently providing a significant source of natural gas supplies for the United States. The federal offshore usually starts 3 miles offshore (e.g., Louisiana), but starts 10 miles offshore of Texas.

Peak Day

The day of maximum demand for natural gas service. In any given area, the "peak day" usually occurs on the coldest day of the year, when demand for natural gas for heating is at its highest. Because each part of the country experiences different weather conditions, the peak day for each region or area is usually different. In some parts of the country, such as the Southeast and the Southwest Central regions, the peak day may occur on the hottest day of the year, when demand for space cooling drives electric generation demand to its highest levels.

PEAK-DAY DELIVERABILITY

The rate of delivery at which a storage facility is designed to be used for peak days.

PEAKING UNIT

An electric generation unit that is only run to serve "peak" demand. An electric generation unit is normally operated during the hours of highest daily, weekly, or seasonal load. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on a "round-the-clock" basis.

***PHILLIPS* DECISION**

In 1954, the U.S. Supreme Court in *Phillips Petroleum Company v. Wisconsin* interpreted the Natural Gas Act as requiring wellhead price of interstate gas to be regulated by the Federal Power Commission.

PIPELINE FUEL

Gas consumed in the operation of pipelines, primarily in compressors.

PIPELINE

A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural and/or supplemental gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use. Also refers to a company operating such facilities.

PIPELINE MODEL

The EEA (Energy and Environmental Analysis, Inc.) model used in the NPC Gas Study, which simulates gas flow from U.S. and Canadian producing regions to consuming regions.

PLAY

A group of geologically related known accumulations and/or undiscovered accumulations or prospects generally having similar hydrocarbon sources, reservoirs, traps, and geological histories.

POOLING POINT

Production area pooling points are areas where gas merchants aggregate supplies from various sources, and where title passes from gas merchant to pipeline shipper. "Paper" pooling areas are places where aggregation of supplies occurs and where pipeline balancing and penalties are determined. (*See* FERC Order 636; Hub.)

POWER POOL

An arrangement used in many regions whereby all dispatchable electric generation is under the operational control of a dispatching center controlled by the power pool, not the individual company that owns the generating equipment.

POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978

This Act was enacted as part of the National Energy Plan and prohibited the use of oil and gas as primary fuel in newly built power generation plants or in new industrial borders larger than 100 million BTU per hour of heat input. PIFUA also limited the use of natural gas in existing power plants based on fuel used during 1974-76, and prohibited switching from oil to gas.

PREBUILD

The "Prebuild" System was authorized in 1977 and provides natural gas from Alberta, Canada, to markets in California and the Midwest. The "prebuild" system is Phase I of the Alaska Natural Gas Transportation System.

PRODUCTION, WET AFTER LEASE SEPARATION

Gross withdrawals less gas used for repressuring and nonhydrocarbon gases removed in treating or processing operations.

PRORATION POLICY

Policies within some gas-producing states that set production limits in order to protect the correlative mineral rights of producers and royalty owners and to prevent physical waste.

Prospect

A geological feature having the potential for trapping and accumulating hydrocarbons.

Proved Reserves

The most certain of the resource base categories as they represent estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Rate Base

The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return.

Refinery Gas

Noncondensate gas collected in petroleum refineries.

Regulatory Lag

Length of time between occurrence of a cost by a regulated entity and the reflection of that cost in the actual rates.

Renewable Energy Sources

Sources of energy, usually for electric generation, that include hydropower, geothermal, solar, wind, and biomass.

Repressuring

The injection of gas into oil or gas reservoir formations to effect greater ultimate recovery.

Reserve Appreciation

The portion of the conventional resource base that results from the recognition that currently booked proved reserves are conservative by definition and will continue to grow over time. This component represents the growth of ultimate recovery (cumulative production plus proved reserves) from known fields that occurs over time.

Reserve Growth

Composed of new reservoirs, extensions, and net positive revisions.

Reserve-to-Production Ratio

Used as an indicator that measures the relative size of ready inventory of gas supply to the current production rate.

Reservoir Pressure

The force within a reservoir that causes the gas and/or oil to flow through the geologic formation to the wells.

Residential Consumption

Gas consumed in private dwellings, including apartments, for heating, air conditioning, cooking, water heating, and other household uses.

Resource Base

Composed of proved reserves, conventional resources (reserve appreciation and new fields), and nonconventional resources (coalbed methane, shales, tight gas).

Resource Cost Curve

A curve that portrays estimates of the wellhead gas price required to develop a certain volume of the resource base and yield a minimum rate of return to the investor.

Resources

Known or postulated concentrations of naturally occurring liquid or gaseous hydrocarbons in the earth's crust which are now or which at some future time may be developed as sources of energy.

Right-of-way

Either a permanent or temporary (during construction) right of access to privately held land for the purpose of constructing and locating pipeline or related facilities. Although ownership remains, in many cases, with the original landowner, the pipeline purchases the right to locate a pipeline under a specific piece of property and the right of access to that land for inspection and maintenance activities. Pipeline right-of-way may be anywhere from 25 feet to 100 feet wide. Typically, at least 75 feet is desired for construction activities, while only 25 feet to 50 feet are maintained as permanent right-of-way.

Risked (Unconditional) Estimates

Estimated quantities of the volumes of oil or natural gas that may exist in an area, including the possibility that the area is devoid of oil or natural gas are risked (unconditional) estimates. Estimates presented in this report are of this nature. For this study, the estimated conventional resource values were used in the model as certain quantities (occurrence probability of 1.0), and the sensitivity of the model results to higher and lower resource estimates was evaluated without quantifying the occurrence probabilities.

Royalty

The gas producer gives the mineral owner a royalty in the form of a share of the gross production of gas from the property free and clear of any production costs or sells the royalty share of gas and gives the owner the gross proceeds in cash.

Section 29 of the Internal Revenue Code

Under this section, income tax credits are available to producers of "nonconventional" fuels, such as gas produced from geopressured brine, Devonian shale, coal seams, tight gas. To be eligible for the credit, gas from nonconventional sources must come from wells drilled before January 1, 1993, and must be produced before January 1, 2003.

Sour Gas

Natural gas with a high content of sulfur and this requires purification before use.

Special Marketing Programs

The FERC permitted pipelines to implement programs that allowed large industrial consumers to arrange purchases of cheaper spot market gas from producers, marketers, and pipelines, with the pipelines serving as only the transporter. These programs were ruled discriminatory by the court and ceased in 1985.

Spot Purchases

A single shipment of gas fuel or volumes of gas, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of gas requirements, to meet unanticipated needs, or to take advantage of low prices.

Steady State Flow

A method of designing natural gas pipeline facilities to meet daily volumetric requirements. Under this method, it is assumed that the same quantity of natural gas flows during each of the 24 hours during a day.

Storage Additions

Volumes of gas injected or otherwise added to underground natural gas reservoirs or liquefied natural gas storage.

Storage Field

A facility where natural gas is stored for later use. A natural gas storage field is usually a depleted oil- or gas-producing field (but can also be an underground aquifer, or salt cavern). The wells on these depleted fields are used to either inject or withdraw gas from the reservoir as circumstances require.

Storage Volume

The total volume of gas in a reservoir. It is comprised of the cushion and working gas volumes.

Storage Withdrawals

Volumes of gas withdrawn from underground storage or liquefied natural gas storage.

Straight Fixed Variable (SFV)

An interstate pipeline transportation rate design that includes all of the fixed costs as part of the reservation change. Under the Modified Fixed Variable (MFV) rate design, costs are divided and some of the fixed costs are allocated back to the demand change.

Sunshine Act

Act passed by Congress with the intent to prevent decisions from being made outside the protection afforded by exposure to public scrutiny.

Synthetic Natural Gas

A manufactured product chemically similar in most respects to natural gas, resulting from the conversion or reforming of petroleum hydrocarbons or from coal gasification. It may easily be substituted for or interchanged with pipeline quality natural gas.

System Supply

Gas supplies purchased, owned, and sold by the supplier or local distribution company to the ultimate end user. System gas is subject to FERC or state tariff and is generally sold under long-term (contract) conditions.

Take-or-Pay

A clause in a natural gas contract that requires that a specific minimum quantity of gas must be paid for, whether or not delivery is actually taken by the purchaser. Contracts entered into currently do not generally include a take-or-pay clause.

Technically Recoverable Resource

Is composed of proved reserves and assessed resources. Assessed resources are that portion of the in-place resource which is estimated to be recoverable in the future at various assumed technology and price levels.

Therm

One hundred thousand British thermal units.

Tight Gas

A component of nonconventional resources which is gas found in low permeability formations (0.1 millidarcy or less).

Top Gas

(*See* Working Gas.)

Transient Flow

A method of designing natural gas pipeline facilities to meet the hourly fluctuations in demand.

Unbundling

On April 8, 1992, the FERC issued Order 636, requiring interstate natural gas pipelines, operating under the FERC's open-access transportation program, to unbundle natural gas sales services from the transportation/delivery service. In practice, this requires affected pipelines to sell natural gas at the pipeline's physical receipt points where natural gas enters the pipeline's facilities, or at designated pooling points. The transportation service necessary to affect delivery of this gas to the customer would be provided under a separate contract. Pipelines would also be required to provide unbundled, separate, storage services. In theory, this will allow all firm customers of the pipelines to purchase natural gas from anyone, with assurance that the delivery service provided by the pipeline will be the same.

Underground Storage

The storage of natural gas in underground reservoirs at a different location from which it was produced.

Underground Storage Injections

Gas from extraneous sources put into underground storage reservoirs.

Underground Storage Withdrawals

Gas removed from underground storage reservoirs.

Undiscovered Conventional Resources

Conventional resources estimated to exist, on the basis of broad geologic knowledge and theory, outside of known fields. Also included are resources from undiscovered pools within the areal confines of known fields to the extent that they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions. For the purposes of this study, undiscovered conventional resources are a portion of the total resource base. Conventional resources are those recoverable using current recovery technology and efficiency but without reference to economic viability. These accumulations are considered to be of sufficient size and quality to be amenable to conventional recovery technology.

Uniform Code

The establishment of a consistent code of regulations that is available to all jurisdictions.

Uniform System of Accounts

Prescribed financial and accounting rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

Vented

Gas released into the air on the base site or at processing plants.

Vintaging

A method for pricing gas at the wellhead that was committed to interstate commerce prior to the passage of the Natural Gas Policy Act of 1978. Price was determined in part by the year in which the gas was dedicated to interstate commerce or the year in which drilling of the well actually commenced. Vintaging was eliminated by FERC Order 451 in November 1986.

Watt

The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthours

The electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electrical circuit steadily for 1 hour.

Well Workover

Work done on a well that improves the mechanical condition of the well or work that treats the reservoir in order to improve gas flow.

Working Gas

The volume of gas in reservoir above the designed level of the cushion gas.

INDEX

E

F

O

P

R

S

T

W

Z

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As input to the NPC Natural Gas study, separate analyses were conducted on the market potential of 10 U.S. regions. Copies of the individual regional reports are being reproduced as NPC working papers in the public interest, and may be obtained from the National Petroleum Council using the order form below. These reports were utilized by the NPC study participants in the course of the NPC study. The NPC **does not** necessarily endorse all of the specific conclusions reached by the regional reports and the regional reports **do not** constitute the advice and recommendation of the National Petroleum Council.

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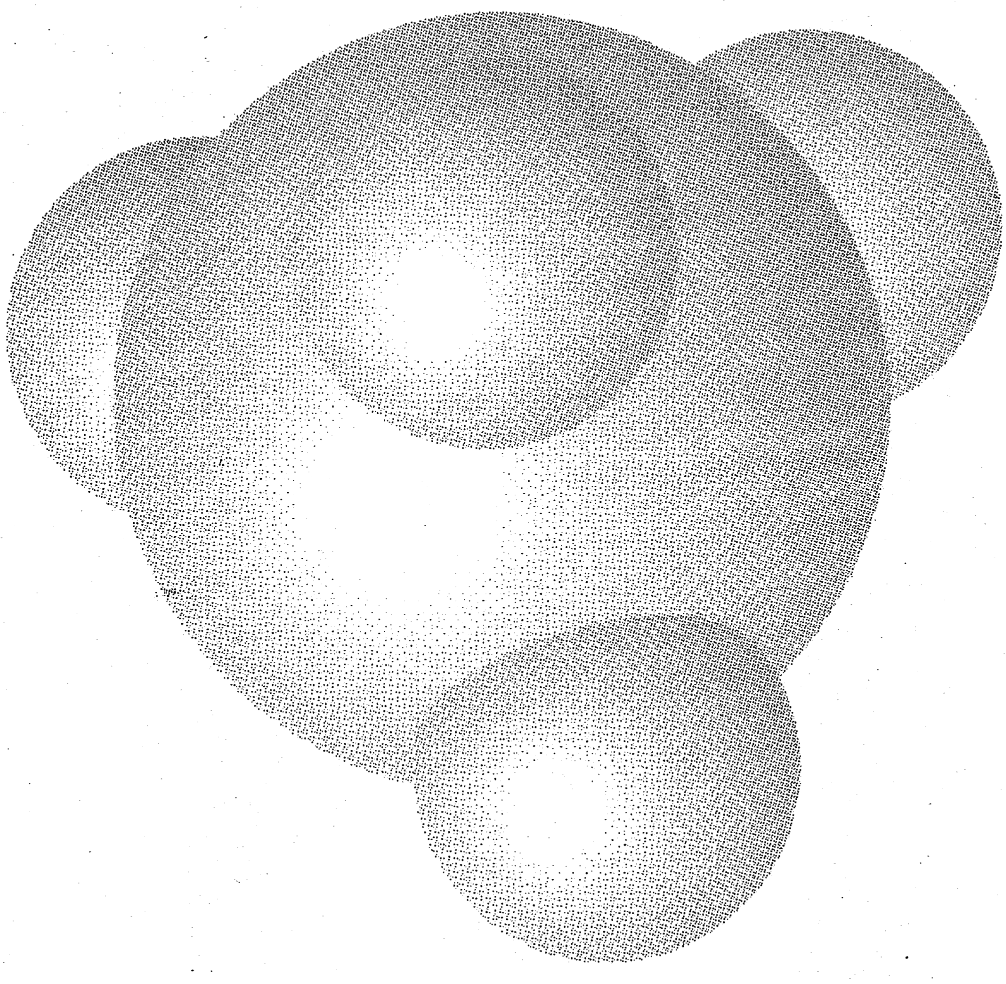

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