NATURAL GAS

Meeting the Challenges of the Nation's Growing Natural Gas Demand

Volume II
TASK GROUP REPORTS

A Report of the
National Petroleum Council

December 1999

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Committee on Natural Gas
Peter I. Bijur, Chair

December 1999

NATIONAL PETROLEUM COUNCIL

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Foreword

This volume, entitled *Task Group Reports,* is part of the National Petroleum Council's (NPC) report, *Meeting the Challenges of the Nation's Growing Natural Gas Demand.* Results of the 1999 study on natural gas (hereinafter referred to as "the 1999 Study") are presented in a three-volume report as follows:

- Volume I, *Summary Report*, provides conclusions and recommendations on the potential contribution of natural gas in meeting the nation's growing demand for energy in the residential, commercial, industrial, and electric power generation sectors. Also included are summaries of key findings from the study's three Task Groups: Demand, Supply, and Transmission & Distribution. Volume I can be viewed and downloaded from the NPC web site, http://www.npc.org.
- Volume II, *Task Group Reports*, contains the results of the analyses conducted by the three Task Groups and provides further supporting details for the conclusions, recommendations, and findings presented in Volume I.
- Volume III, *Appendices*, includes output of the study's computer modeling activities as well as various source and reference materials developed for or utilized by the Task Groups in the course of their analyses. The Council believes that these materials will be of interest to the readers of the report and will help them better understand the results. The members of the National Petroleum Council were not asked to endorse of approve all of the statements and conclusions contained in Volume III but, rather, to approve the publication of these materials as working papers of the study.

  Enclosed with Volume III is a CD-ROM containing further model output on a regional basis. The CD also contains digitized maps, which were used in assessing a key critical factor—access to resources and rights-of-way. These maps provide a comprehensive inventory of acreage by land-use categories associated with related USGS gas plays for the several key Rocky Mountain resource areas analyzed in the 1999 NPC Study.

An outline of the full report and a form for ordering additional copies can be found in the back of this volume.

Study Background

The initial impetus for the 1999 Study came from a letter dated May 6, 1998, in which then-U.S. Energy Secretary Federico Peña requested the NPC to:

> Reassess its 1992 report [*Potential for Natural Gas in the United States*] taking

into account the past five years' experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond. Of particular interest is the Council's advice on areas of Government policy and action that would enable natural gas to realize its potential contribution toward our shared economic, energy, and environmental goals.

In making his request, the Secretary noted that "at least two major forces ... are beginning to take shape which will profoundly affect energy choices in the future – the restructuring of electricity markets and growing concerns about the potentially adverse consequences that using higher carbon-content fuels may have on global climate change and regional air quality." Further, the Secretary stated that "For a secure energy future, Government and private sector decision makers need to be confident that industry has the capability to meet potentially significant increases in future natural gas demand." (See Appendix A for this letter and Secretary Bill Richardson's follow-up letter expressing his interest in receiving the NPC's advice on these matters.)

To respond to this request, the NPC established a Committee on Natural Gas, which, in turn, established a Coordinating Subcommittee and three Task Groups to assist it in conducting the study.

- *NPC Committee on Natural Gas*—chaired by Peter I. Bijur, Chairman of the Board and Chief Executive Officer, Texaco Inc., with T. J. Glauthier, Deputy Secretary of Energy, serving as the Committee's Government Cochair. H. Leighton Steward, Vice Chairman of the Board, Burlington Resources, Inc., and William A. Wise, President and Chief Executive Officer, El Paso Energy Corporation, served as Vice Chairs for Supply and for Transmission & Distribution, respectively.
- *Coordinating Subcommittee*—chaired by Rebecca B. Roberts, Strategic Partner, Global Alignment, Texaco Inc., with Robert S. Kripowicz, Principal Deputy Assistant Secretary, Fossil Energy, U.S. Department of Energy, serving as Government Cochair.
- *Demand Task Group*—chaired by Matthew R. Simmons, President, Simmons and Company International, with James M. Kendell, Director, Oil and Gas Division, Office of Integrated Analysis and Forecasting, Energy Information Administration, U.S. Department of Energy, serving as Government Cochair.
- *Supply Task Group*—chaired by Thomas B. Nusz, Vice President, Strategic Planning and Engineering, Burlington Resources, Inc., with Guido DeHoratiis, Director, Oil and Gas Upstream R&D, Office of Fossil Energy, U.S. Department of Energy, serving as Government Cochair.
- *Transmission & Distribution Task Group*—chaired by Susan B. Ortenstone, Vice President, El Paso Energy Corporation, with Joan E. Heinkel, Director, Natural Gas Division, Data Analysis & Forecasting Branch, Energy Information Administration, U.S. Department of Energy, serving as Government Cochair.

(Appendix B contains the Committee roster along with the rosters of its Coordinating Subcommittee and three Task Groups.)

Key Differences from 1992

The Secretary was correct in noting that the U.S. energy markets have changed significantly since the 1992 NPC study on natural gas (hereinafter referred to as "the 1992 Study"). The U.S. economy is growing more rapidly than was anticipated in 1992, and with that growth has come a higher natural gas demand than was expected. Environmental regulations that favor natural gas consumption are more firmly in place than in 1992 and environmental restrictions on fossil fuel-burning facilities are increasingly stringent. In fact, gas demand has grown at a rate that exceeds even the most robust scenario projected in the 1992 Study. Continued economic growth as well as concerns about air quality and climate change favor the continued expansion of natural gas demand.

Since 1992, the gas industry has undergone a significant restructuring. The primary impetus came from Federal Energy Regulatory Commission (FERC) regulations that, over time, have converted interstate pipelines from sellers and transporters of natural gas to solely transporters. State regulators and local distribution companies (LDCs) are moving toward a similar result in many jurisdictions. This restructuring has driven changes in roles and risks for industry participants because a number of market functions and obligations formerly managed under the auspices of the LDCs and pipelines must now be accepted and carried out by other market participants. Since the 1992 Study, new market structures—market hubs/centers, futures trading for natural gas, and a capacity release market (a secondary pipeline capacity market)—have either developed or matured. Other financial tools have been developed to reduce the risk of price change to buyers and sellers over extended time periods. In short, the gas market has become highly efficient and sophisticated, with numerous participants ensuring competitive prices. Increased confidence in the functionality of the gas market and competitive gas prices has played a significant role in increasing gas demand.

The industry has benefited from remarkable progress in technology in areas that were not fully anticipated in 1992. For example, three-dimensional (3D) imaging now allows scientists to virtually "see" underground rock formations in graphic detail and to reduce drilling risk by more accurately predicting locations for hydrocarbon deposits. Progress in 3D and 4D seismic technology, in conjunction with imaging technology, has allowed producers to spot small hydrocarbon accumulations. Improved drilling techniques enable production companies to more precisely hit drilling targets and accomplish difficult maneuvers such as drilling a vertical well, turning a corner, and then drilling horizontally over five miles. New technology now allows producers to access supply in ocean waters that are more than a mile deep. These improvements, along with many more, have resulted in significant reserve additions and prospects of new production in areas that were once considered physically or economically unreachable.

Technological progress has also been evident in the transmission and distribution segments of the industry and has contributed to a steady and significant decline in transmission and distribution charges since the mid-1980s. Technological advances have taken place in areas such as gas measurement, pipeline monitoring, compression, and storage management. The dramatic improvements in information and communications technology have contributed to more efficient data management systems that support marketing activities and capacity scheduling. New end-use gas technologies, such as higher efficiency residential furnaces, natural gas cooling, and combined cycle power plants, continue to offer consumers higher efficiency, lower costs, and cleaner energy.

Although market confidence has grown and technology has improved the state of the industry, recent events have led to questions about the industry's ability to meet the demand growth potential. The downturn in world oil prices between late 1997 and early 1999 dealt a heavy blow to the exploration and production sectors of the U.S. gas industry, particularly to the oilfield supply/service contractors and the independent producers who supply over half of the nation's natural gas needs. Industry participants experienced an extended period of poor economic returns and, fearing a repeat of the 1984–89 depression in the industry, responded with significant downsizing and cutbacks in spending. Investment capital for developing new production, which for most industry participants is highly dependent on cash flow from crude oil and gas sales, declined dramatically in 1999. As a result, new supply development in the United States has slowed considerably. Although oil prices have now rebounded, these events have highlighted the boom and bust nature of the business and have made industry participants and investors very cautious.

Several other trends highlight the challenges that could impact the future of gas production and delivery. The broadening and extension of moratoria have reduced access to a portion of the nation's natural gas resource base. The economic hardship experienced by the oilfield supply/service sector has limited construction of rigs and other infrastructure, giving rise to questions on the industry's ability to respond to future drilling needs. Decreased spending on research and development gives rise to concerns regarding future technological breakthroughs. Continued cutbacks and layoffs impair the industry's ability to attract new employees.

While these issues are significant, the NPC wishes to emphasize that the industry has successfully met difficult challenges in the past and has proved to be resilient and resourceful. Each of the challenges identified in the 1999 Study can be met if immediate, cooperative, and focused actions are taken by the industry and the government. (See Volume I, *Summary Report*, for an overview of the 1999 Study's conclusions, recommendations, and key findings.)

Approach to the 1999 Study

In conducting the 1999 Study, the NPC Committee on Natural Gas and its Coordinating Subcommittee and three Task Groups developed projections for gas demand, gas supply, and gas transmission and distribution. The primary focus of the 1999 Study was to test supply and delivery systems against significantly increased demand. As in the case of the 1992 Study, the Committee on Natural Gas selected Energy and Environmental Analysis, Inc. (EEA) to run econometric models for the analysis. The Coordinating Subcommittee and its Task Groups provided data and assumptions to EEA for inclusion in the development of a Reference Case for the focus period of 1999 to 2010. The assumptions used in the Reference Case represent a plausible view of the future and were selected with full understanding that, in reality, each could vary significantly. Each of the Task Groups developed sensitivity analyses to test the Reference Case through 2010 and to develop an extended view through 2015. The results of the Reference Case and the sensitivity analyses form a framework for better understanding the factors that influence supply and demand balances. This approach was particularly useful in exploring the potential range of outcomes beyond 2010, a point at which uncertainties in assumptions begin to escalate. Throughout this report, data are reported for the focus period of 1999 to 2010, with an extended view for the more uncertain period of 2011 through 2015. While the 1999 Study did not attempt to model supply and demand beyond 2015, the issue of long-term sustainability is addressed.

The 1999 Study participants endeavored to focus on the broader industry implications and dynamics indicated by the data rather than attempt to forecast specific end results. Issues such as new regulations for climate change were not examined in detail, but other factors that increase demand were specifically analyzed and some correlations can be made. Changes that are occurring in the areas of electricity generation, such as distributed generation, were not studied, but the overall impact of increases in gas demand due to electricity generation were examined.

The NPC believes that the results of the 1999 Study are amply supported by the rigorous analyses conducted by the Committee on Natural Gas and its subgroups. Further, the NPC wishes to emphasize that the significant growth in demand that is projected in the 1999 Study is based on long-term trends and should not be interpreted as a "goal" of the industry. However, as natural gas demand continues to expand, the natural gas industry stands ready to work with all stakeholders to economically develop the natural gas resources and infrastructure necessary for continuing the nation's economic growth and meeting its environmental goals.

DEMAND TASK GROUP REPORT

Table of Contents for Demand Task Group Report

Overview

The news from the Demand Task Group is that record demand for natural gas can be projected well into the future. The investigation and studies conducted by the Demand Task Group have produced three key findings: (1) gas demand grew much faster than the projections made in the 1992 NPC study on natural gas (hereinafter referred to as "the 1992 Study"); (2) gas demand is projected to increase by 36% between 1998 and 2010 and nearly 50% by 2015; and (3) new environmental regulations could add significant incremental gas demand.

The increase in demand that is projected in this study presents tremendous opportunities for the industry. Understanding the extent of the opportunity is critical to all segments of the industry. The drivers that will produce the increase are already in place. For example, electricity generators have already ordered many of the combined-cycle gas plants that will create much of this growth in demand. Many other plants, though not on order, inevitably will be ordered because electricity generators have foregone alternatives—such as greenfields coal plants—that would have required longer lead times to implement. Enormous effort by all segments of the industry is required immediately. Wells must actually be drilled; gathering lines and processing plants must be built; new pipelines must be constructed and existing lines expanded.

Government, too, must understand the magnitude of both the opportunities and the challenges. Natural gas is the answer to many of the energy and environmental concerns that confront government on the road to 2015. But natural gas will not automatically become available on time and in the proper location without a proactive government effort supporting industry efforts.

Gas is in fact an idea whose time has come. But much needs to be done to make this idea a reality. Government and industry, armed with an understanding of the concerns expressed in this report, must act jointly to assure that the potential of natural gas, as outlined herein, is realized.

Chapter One

The Reference Case— A Bottom Up Analysis

The 1992 NPC Study

As noted in the Summary volume, the NPC Committee on Natural Gas appointed a task group to develop projections for gas demand. As in the case of the 1992 Study, the Committee on Natural Gas selected Energy and Environmental Analysis, Inc. (EEA) to run econometric models for the analysis. The Demand Task Group began its work by studying the EEA model and the assumptions and results of the 1992 Study. The EEA demand model was adopted to provide the analytical framework for this study. (See the CD-ROM in Volume III, *Appendices*, for a description of the EEA model.)

In reviewing the high and low forecasts for 2010 developed in the 1992 Study, it was apparent that Case 2, the "low case" scenario, was a low growth scenario that had proven to be so far from actual results that it did not merit further study or analysis. Even Case 1, the "high case" scenario, had proved to be too low to capture the real growth that occurred in the 1992–98 period. The Demand Task Group felt, however, that Case 1 had proved close enough to reality to merit study (see Figure D-1).

Comparison of 1992 Projected Data vs. Actual

Table D-1 compares the projections of the 1992 Study with actual demand for 1997 and 1998. Note in Table D-1 that by 1997 residential consumption had grown to 102% of the high case volume predicted for 2010 and commercial to 91% of 2010 high case volume. By 1998, industrial demand had grown to 101% of the predicted 2010 volume. Weather during this period was warmer than normal in five of the seven winters during the period. Gas used for electricity generation in 1998 was 61% of the amount predicted for 2010, but the slow growth in this category is accounted for by the data reporting problems discussed in the "Background of Data" section later in this chapter. In total, demand in 1997 for all end uses had already reached a level equal to 87% of the 2010 forecast although 13 years of the 18-year study period then remained. Stated another way, in 1998 U.S. gas demand was over 1 trillion cubic feet (TCF) higher than was projected by the 1992 study for that year.

Various questions are raised by the comparison of the 1992 projections with actuals. First, why were the 1992 projections too low? Second, what could be learned from these errors? The Demand Task Group felt there was no real problem with the model used in 1992 or the modeling methodology planned for the 1999 Study. The problem in the 1992 Study lay with the assumptions. (By the same token, if the 1999 Study has problems, the culprit will also be the assumptions that go into the model. The effect of varying key assumptions in the 1999 Study is analyzed in Chapter Three of this Demand Task Group Report.)

Figure D-1. Comparison of Actual Demand versus 1992 Projections

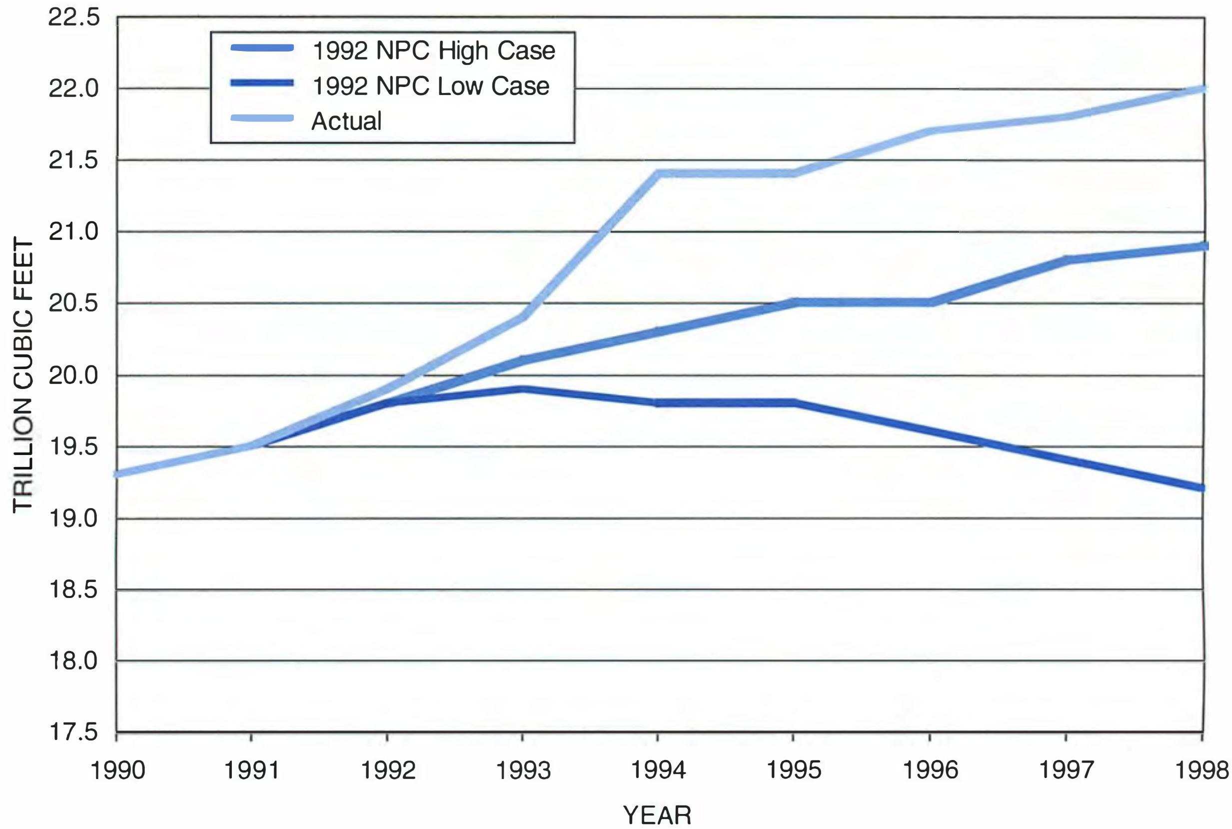


TABLE D-1

END-USE GAS DEMAND*
1992 STUDY COMPARED TO 1997 AND 1998 ACTUAL
(Trillion Cubic Feet)

	1992 Study High Reference Case-2010	1997 Actual Demand	1998 Actual Demand
Residential	4.8	5.0	4.5
Commercial	3.4	3.2	3.0
Industrial	8.6	8.8	8.6
Electricity Generation	5.2	3.0	3.3
Net Storage Fill/Balance	0	0	0.6
Total	**22.0**	**20.0**	**20.0**

*Does not include lease, plant, and pipeline fuel.

Source: The 1992 NPC Study and the Energy Information Administration.

In comparing the assumptions used in the 1992 model with actual events, the Demand Task Group noted several discrepancies. One, the 1992 Study assumed a growth in gross domestic product (GDP) of 2.4% per annum over the study period. GDP growth rates vary substantially depending on the period selected. Actual growth in GDP over the 1990–98 period was 2.6%. The 1990–98 period experienced one recession in 1991 when GDP fell by 0.9%. Over the 1992 to 1998 period, GDP growth was 3.2%. GDP growth in 1997 and 1998 was 3.9% and it appears that GDP growth in 1999 will be approximately 4%. As this report was being written, third quarter 1999 GDP was reported to have increased by 5.5% over the previous year. Clearly, the economy was growing much faster than was predicted in the 1992 Study or, for that matter, as forecast in current estimates from other groups.

The 1992 Study also assumed a higher level of energy conservation than in fact occurred. The earlier study assumed that the slope of conservation improvement would continue to follow the pattern of the immediately preceding 20 years of increasing conservation. In retrospect, a change in the angle of the slope occurred around 1988 reflecting a reduced rate of improvement in conservation (see Figure D-2).

It should be emphasized that the economy continues to consume less energy per dollar of GDP, but this trend has flattened considerably from the sizeable drop experienced in the 1980s (Table D-2). In short, the economy

Figure D-2. Energy Consumption Per Dollar of GDP

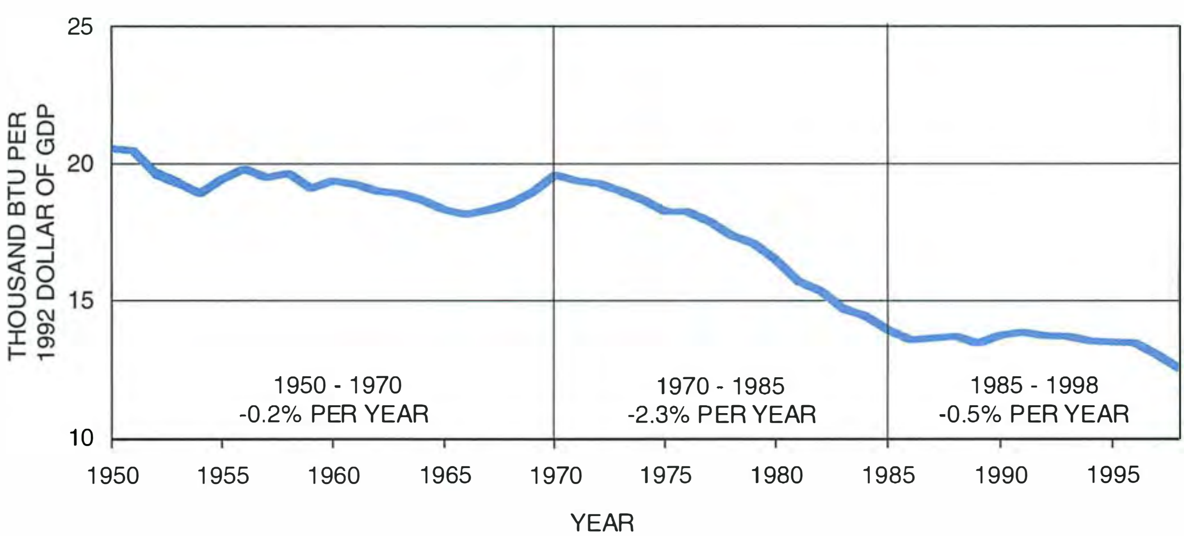


TABLE D-2

ENERGY CONSUMPTION PER REAL DOLLAR OF GDP
(Btu per Dollar of GDP)

	1992	1993	1994	1995	1996	1997	1998
Petroleum & Natural Gas	8.59	8.56	8.47	8.40	8.35	8.11	7.81
Other Energy	4.56	4.57	4.48	4.50	4.53	4.37	4.23
Total	**13.15**	**13.13**	**12.95**	**12.90**	**12.88**	**12.47**	**12.04**

Source: Energy Information Administration, *Monthly Energy Review*, October 1999.

continues to use energy more efficiently; it simply is less efficient than the 1992 Study anticipated.

Background of Data

Because actual and projected gas consumption data are used throughout the Demand Task Group Report, it is important to understand how the data have been collected and reported historically. For this reason, an extended discussion follows of the data concerning the Industrial and the Electricity Generation categories. It is also important to understand that the data for the Residential and Commercial categories are impacted to a significant degree by the impact of winter weather on space heating loads. In both cases, the data set forth in the report are accurate. However, one cannot understand what the data mean without understanding something about how they are put together and what factors are responsible for shifts in data between years.

ELECTRICITY GENERATION

For decades, detailed historical data have been collected for primary energy consumed by regulated electric utilities and the sale of electricity by the utilities to end-use customers. This information has been reported monthly by the Energy Information Administration (EIA) since early in its existence and has allowed detailed analysis of electricity markets. Much less detailed data were collected concerning energy consumed for electricity generation by industrial energy users. These users, such as large aluminum smelting plants, purchased gas or other fuel sources to generate electricity as well as steam or other process heat. Energy consumption by these users has been classified as Industrial.

Cogeneration, the combined production of electricity and steam or process heat, became a growing source of electricity sold by electric utilities with the adoption of the Public Utility Regulatory Policy Act of 1978, which required utilities to buy power generated by "qualified facilities." Growth in gas demand from cogeneration, reported as industrial sector consumption, thus reduced sales to electric utilities and reduced utility purchases of gas or other primary energy for electricity generation in the decade of the 1990s. As a result, some portion of electricity generation was effectively transferred from Electricity Generation (which was formerly titled Electric Utility) into the Industrial category.

With the emergence of independent power producers (IPPs) one more complication was introduced into the data. IPPs, because they were not "electric utilities," were classified as Industrial and their consumption so categorized. Since nearly all of the kilowatt-hours produced by IPPs to date have been sold to electric utilities for resale, more energy purchases were again effectively transferred from what would have been the Electric Utility category to Industrial. With increasing deregulation of the electric utility industry, many utilities are divesting generation assets and selling them to IPPs. A further transfer of volumes from Electric Utility to Industrial, of course, is the result.

The problem described above has been widely recognized in industry and government and a satisfactory solution has not yet emerged. Recently, EIA has begun to publish *annual* data derived from survey results (which the Demand Task Group believes to be the only available data reported to EIA) in an attempt to estimate all non-utility generation (NUG) and related primary fuel consumption. The published annual data do not appear to differentiate between cogeneration and IPP generation. Comparison of the annual data to other sources leads to the conclusion that the vast majority (approximately 85%) of the 2.4 TCF of NUG gas consumption reported by EIA is cogeneration. At the same time, EIA—appropriately—continues to collect and publish the *monthly* data in the form used to date, that is to say, with cogeneration and NUG reported under Industrial.

The Demand Task Group notes its opinion that the admixture of Electricity Generation data with more traditional demand in the Industrial category makes growth comparisons very difficult. The Task Group suggests that government and industry work together to devise a solution that will produce data (including monthly data) that would appear more meaningful in light of changing trends in the electricity markets. The Task Group further suggests that cogeneration should be left in the Industrial category because much of the electricity and heat is consumed on site or in the immediate vicinity.

IPP fuel consumption should be reported under Electricity Generation because it serves the needs of other customers. Users of this report are cautioned to remain cognizant of the data background and to make future comparisons of actual demand with the projections in this report in light of changes that may be instituted in the way data are reported and categorized.

IMPACT OF WINTER WEATHER ON HEATING LOADS

Since space heating loads are the primary use of gas in the Residential and Commercial categories, winter weather has a very significant impact on consumption reported in these two categories. The severity of winter weather is measured by heating degree days (HDDs). (HDDs are explained in the "Weather" section later in this chapter.) More HDDs increase space heating loads; fewer HDDs reduce loads. For this reason, conclusions based on comparisons of consumption at historical points in time are misleading unless adjusted for weather. Table D-1 juxtaposes gas demand data for 1997 in order to illustrate the weather-sensitive nature of gas demand. Residential and commercial gas demand in 1998 was 700 billion cubic feet (BCF), or 8%, lower than 1997 demand. This decline was solely a result of the varying severity of the winter and the regional patterns of the weather in those two years. Total HDDs declined by 11% from 4,546 HDDs in 1997 to 4,029 HDDs in 1998. In contrast, gas demand in industrial and electricity generation applications was 300 BCF larger in 1998 than it was in 1997. Increased industrial output and cooling requirements and increases in gas electricity generation requirements account for a significant portion of the difference. (In addition, the increase in demand in those end-use categories reflected such temporary causes as successful inter-fuel competition with fuel oil and the availability of inexpensive released firm and interruptible pipeline capacity to deliver gas to these price sensitive sectors.)

Key Assumptions in 1999 Study

After a review of the 1992 Study, the Demand Task Group began an analysis of the key assumptions to be used in preparing the 1999 Study. The discussion that follows summarizes the thinking that went into selecting the assumptions used in running the Reference Case model. Although the Task Group adopted what it believes to be the most reasonable assumptions, it nevertheless studied the effect of changing key variables. This sensitivity analysis is set forth in Chapter Three of this Demand Task Group Report and allows the reader to make his own adjustments in the demand forecast based on changes in the Reference Case assumptions.

Gross Domestic Product

Gross domestic product reflects the changes in economic activity in a nation and thus is one of the primary drivers of gas demand. In the 1999 Study, U.S. GDP was assumed to grow at an annual rate of 2.5% throughout the period. Canadian GDP was assumed to grow at an annual rate of 2.2% throughout the period. The Task Group reviewed the past history of growth in GDP in an effort to arrive at the most reasonable assumption concerning growth rates. GDP is defined in the box below:

Definition of Gross Domestic Product

$$GDP = C + I + G + X - M$$

C = Consumption (Autos, Retail Sales, Personal Consumption Expenditures)
I = Investment (Housing, Durable Goods, New Homes, Construction, Inventories)
G = Government (Receipts/Taxes and Expenditures/Transfer Payments)
X = Exports
M= Merchandise Imports

The primary drivers of real GDP growth are population and productivity—simply, how many people are producing goods and services and how much can each person produce in a given period? The rate of population growth in the United States is projected to decline, from 1.0% per year in the 1990–98 period, slowing to 0.5% per year by 2010. In addition, the labor force participation is expected to decline with the "graying of the

Boomers." The measurement of productivity is currently the subject of some mystery; recent remarks by Alan Greenspan suggest that currently reported data underestimate the growth in productivity (see Appendix G), and some changes in methodology were made during 1999. Although the logic of those who predict a gradual decline in the rate of GDP growth is difficult to refute, the Task Group was troubled by the fact that the logic of the case for lower growth has not been manifest in the numbers for the 1997–99 period. If anything, the GDP results over the 1992–99 period cast doubt on the prevailing wisdom and suggest that new factors—perhaps those suggested by Chairman Greenspan—are at work in the U.S. economy.

The Demand Task Group was also troubled by the problem of reflecting recessions in an assumed future growth rate. Occurrence of the event itself is not a certainty, much less the timing. Various scenarios were tested (see sensitivity analysis in Chapter Three of this Demand Task Group Report). Rather than predict the occurrence of one or more recessions, the Task Group simply assumed that a 2.5% rate would represent the average growth experienced in the study period including periodic recessions and recoveries; high and low sensitivities were run at 3.0% and 2.0%, respectively. The 2.5% rate is greater than the 2.4% used in the 1992 Study, but slightly lower than the 2.6% experienced in the period from 1990 to 1998 and considerably lower than the 3.9% in 1997 and 1998 and an estimated 4.0% in 1999. The estimates of GDP used in the 1992 Study utilized a 1990 base. The 1992 forecast was not adjusted to reflect the 1991 recession then in progress. Relatively rapid growth from 1991 through 1998 has wiped out the effect of the 1991 recession and produced an average compound growth rate of 2.6% for the 1990–98 period. (It should be noted that the 1992 Study used "unchained" GDP data whereas the 1999 Study uses the more appropriate "chained" data.)

Canadian GDP was assumed to grow at a rate of 2.2%. Historically, the growth rate of Canadian GDP has been 0.3% lower than the rate of growth for U.S. GDP. The Task Group notes, however, that as in the case of recent U.S. growth rates, the Canadian growth rate in recent years is well above the 2.2% rate assumed in the 1999 Study. Also, *Canadian Energy—Supply and Demand to 2025*, recently issued by Canada's National Energy Board, forecasts a GDP growth of 2.55% per annum from 1997 to 2010 and 2.45% to 2015.

U.S. Industrial Production

GDP growth at an annual 2.5% level is assumed to generate an annual growth rate of 3.0% in U.S. industrial production. An increase in rate of growth in GDP results in a corresponding increase in the growth rate of industrial production. Growth in industrial production in turn drives growth in demand for natural gas in several sectors.

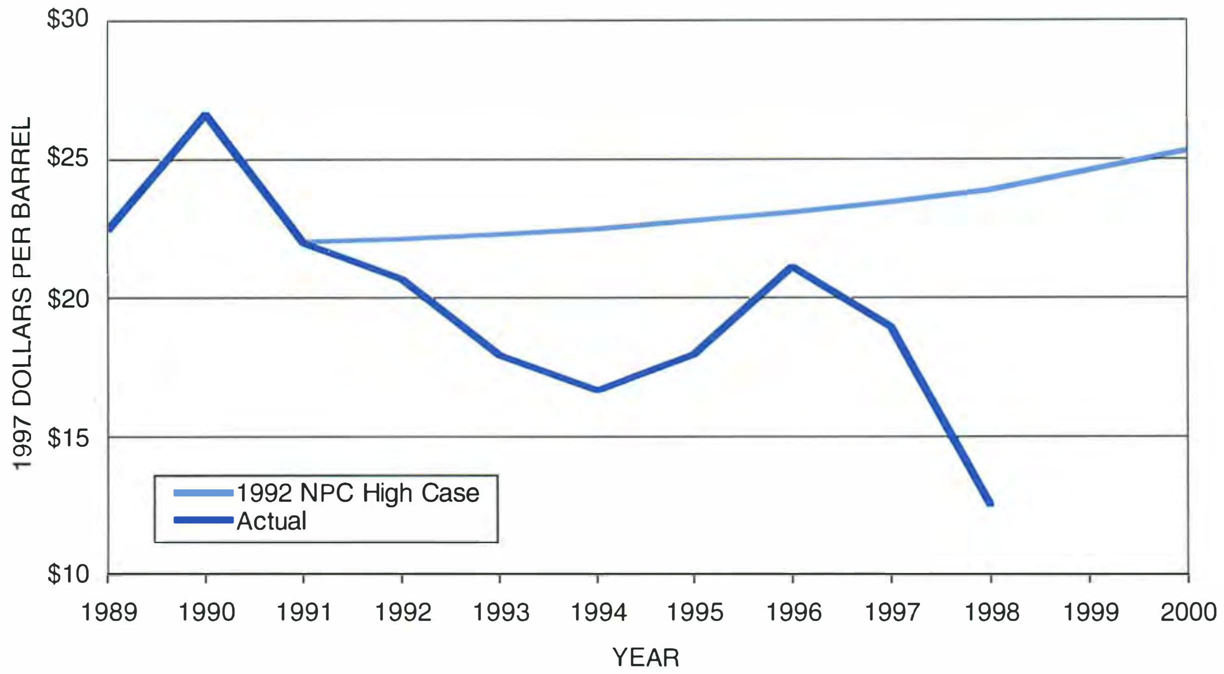
Alternative Fuels

Because of their impact on gas demand, the prices of alternative fuels were also assumed in running the model. In view of the recent collapse of West Texas Intermediate (WTI) oil prices to the $12/bbl range and subsequent recovery to the $25/bbl area, it was difficult to derive a price from recent performance in the oil markets. The Demand Task Group elected to use a historical average oil price based on the familiar WTI oil price. The Reference Case assumed a price of $18.50/bbl in 1999 dollars. Oil prices quoted in the 1992 Study represented Refiner Acquisition Cost of Crude (RACC), which tends to be a lower number than the more familiar WTI numbers. Note in Figure D-3 that actual RACC prices were well below the prices predicted by the 1992 Study. The RACC price for the 1999 Study was assumed to be $16.50/bbl in 1999 dollars.

Coal price FOB at the mine was assumed to be $1.25 per million British thermal units (MMBtu) in December 1998, with an annual increase of 1.0% producing a price of $1.41/MMBtu by 2010 and $1.48/MMBtu by 2015.

It should be noted that coal prices per MMBtu in 1998 are much lower than the price of gas at the same point in time ($2.345/MMBtu NYMEX near month average for December). Comparing cost of fuel alone would suggest that coal has a competitive advantage over natural gas. In reality, the two prices are not comparable due to varying heat rates obtained with each fuel in individual generation stations and the far higher capital

Figure D-3. U.S. Average Crude Oil RACC Price



cost to construct new coal-fired electricity generation plants. Also, construction time for coal-fired plants is two to three times as long as for gas-fired plants and permits for coal-fired plants are more difficult to obtain.

Electricity Demand

The electricity demand forecast relies on econometric relationships that consider growth in GDP and weather, i.e., electricity demand is not an *assumption*, but is derived by *running the model* with the indicated assumptions. Electricity demand for space heating and cooling is affected by both summer and winter weather. Insofar as space heating is concerned, colder than normal weather also creates an increased demand for electricity. Obviously, a warm summer creates a greater demand for electricity used for air-conditioning purposes.

Electricity demand growth projected for the study period is greater than recent North American Electric Reliability Council (NERC) forecasts. The model predicts the annual growth rate in electricity demand will be 2.1% for the 1999 to 2010 period and 2.0% for the 2010 to 2015 period. This assumption may well be too low. As a point of reference, net electricity generation grew by a compound rate of 2.6% from 1973 through 1998. The rate of electricity growth from 1989 to 1998 was 2.3%, but this figure only reflects growth in utility sales and does not count electricity generation for on-site use. It is possible that electricity demand data will rebound to the 1973–98 average of 2.6%.

The level of electricity demand is extremely important in projecting demand for natural gas, oil, and coal. Electricity is not a primary source of energy as are natural gas, oil, and coal. Rather, electricity is a secondary source, which requires the consumption of a primary source of energy to produce it. The laws of thermodynamics as applied to the generation of electricity dictate that many more Btu of primary energy will be input into the process than will emerge in the form of electricity. According to Table A-8 of the EIA's *Monthly Energy Review* (November 1999), the average heat rate during 1998 for the United States as a whole was 10,311 Btu per kilowatt-hour. Because 1 kilowatt-hour equals 3,412 Btu, average energy efficiency of electricity generation can be calculated as 33%. In addition, there are losses in transmitting electricity from the bus bar of the generating plant to the end-user; those losses vary from 6% to 10%

depending on the distance transported. Thus, as electricity demand grows, it exerts a multiplying effect on demand for primary energy in excess of 3:1. For this reason, it will be important to monitor trends in growth of electricity demand.

Summarizing, there are currently four primary methods of generating electricity. Of these, (1) nuclear is at maximum capacity and near maximum utilization, (2) hydro is at maximum capacity and utilization, and (3) coal is at maximum capacity but may be able to increase utilization. Additional electricity demand—translated and multiplied into demand for primary energy—will fall on the fourth method: natural gas supplemented by oil. The detailed discussion that follows amplifies this fundamental conclusion.

Capacity Utilization of Electricity Generating Plants

COAL

The amount of each fuel consumed in meeting electricity generating demand is based on the capacity of plants utilizing each fuel and the utilization rate of each type of plant. Coal-fired generating plant capacity is assumed to remain at 320 gigawatts in 2010. It was further assumed that through 2010 the cost of electricity generated from coal (including capital costs) would not be competitive with electricity from gas, but that after that date an estimated 20 gigawatts of new coal-fired capacity would be built.

While no significant amounts of new coal-fired capacity are projected in the Reference Case prior to 2010, increased utilization of existing coal-fired plants is assumed to compete successfully with newly constructed gas-fired electricity generation. The ongoing restructuring of electricity markets provides a strong incentive to increase the use of the existing capital investment. Moreover, since the variable cost of operating coal-fired units is usually lower than the fully allocated cost of new gas-fired generation, increasing the hours of operation for coal-fired units to their technical limits is more economic than building new gas-fired units for base load use. Although additional investment to improve operating efficiency and meet emission requirements will be required, the basic conclusion remains unchanged.

The large base of coal-fired capacity—utilization of which has grown from 55% in the late 1980s to 63% in 1998—provides an opportunity for growth in coal-fired electricity generation through improved utilization of installed capacity (see Figure D-4). Indeed, between 1998 and 2010, 29% of the projected incremental electricity demand growth is projected to be met through increased utilization of existing coal-fired capacity. Coal-fired capacity utilization is assumed to increase 11 percentage points from 64% in 1997 to 75% by 2010.

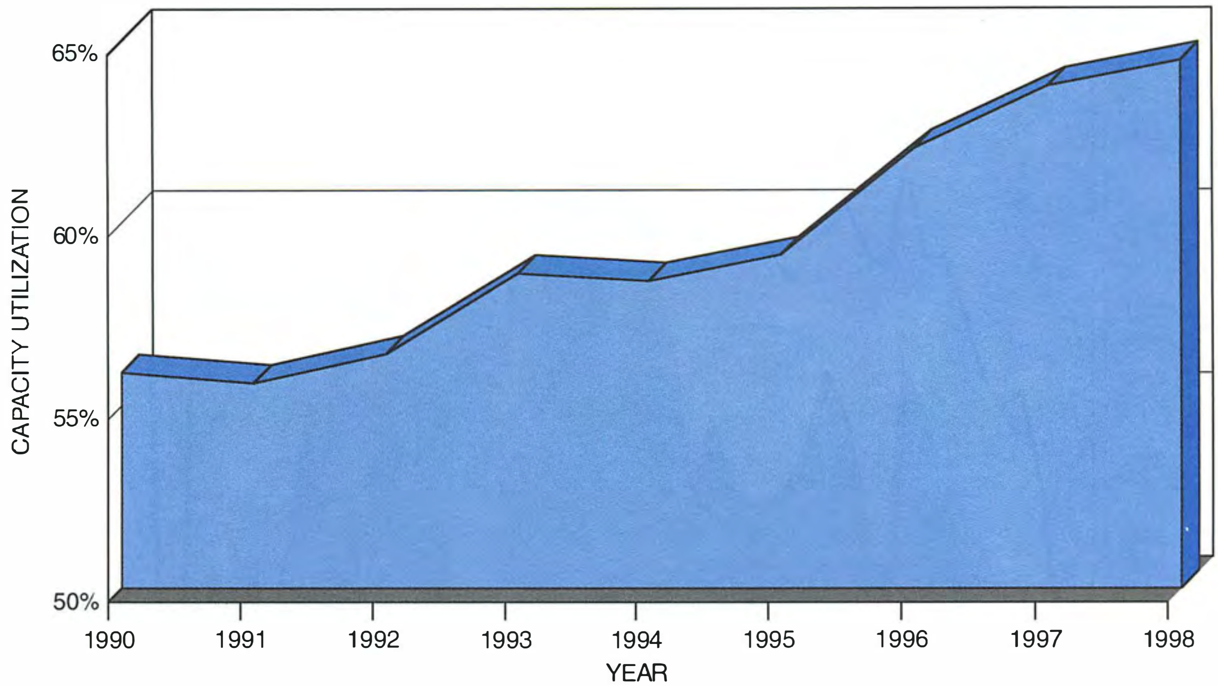
Continued improvement in coal-fired capacity utilization will be a considerable challenge for owners of generating stations. An analysis of existing coal-fired capacity suggests that the greatest portion of coal-fired capacity is composed of relatively new, large units. Figure D-5 shows the age and size of existing coal-fired units, the "in service" date of the installed coal boiler, and the number of units built in that year.

Nearly 330 gigawatts of coal-fired capacity was built from 1921 through 1996. Less than 5% of this capacity has been retired so far, leaving 320 gigawatts of coal-fired capacity on line by 1998. During the period from 1967 through 1986, 67% or 222 gigawatts of coal-fired capacity was added, predominately through the construction of large units. The average size of units added from 1967 through 1996 was nearly twice as large, 475 megawatts per boiler, as the average for the whole period, which was 165 megawatts per boiler.

Figure D-6 presents 1996 capacity utilization data for existing coal-fired units as a function of the "in service" date of the unit. Figures D-5 and D-6 indicate that the bulk of coal-fired capacity is comprised of large, relatively new units that are likely to be loaded heavily by operators. And there is still the opportunity for these units to contribute more to electricity demand requirements through improved utilization.

Nevertheless, there remains considerable uncertainty regarding the ability of coal-fired plants to reach 75% capacity utilization. A brief explanation of how capacity utilization is calculated is in order. If a particular plant were operated 24 hours a day at full load, 365 days a year, it would have a 100% capacity

Figure D-4. U.S. Central Utility Coal-Fired Electricity Generation Capacity Utilization



Source: DOE/EIA, *Electric Power Annual*, 1990–1998.

Figure D-5. Coal-Fired Plant In-Service Dates

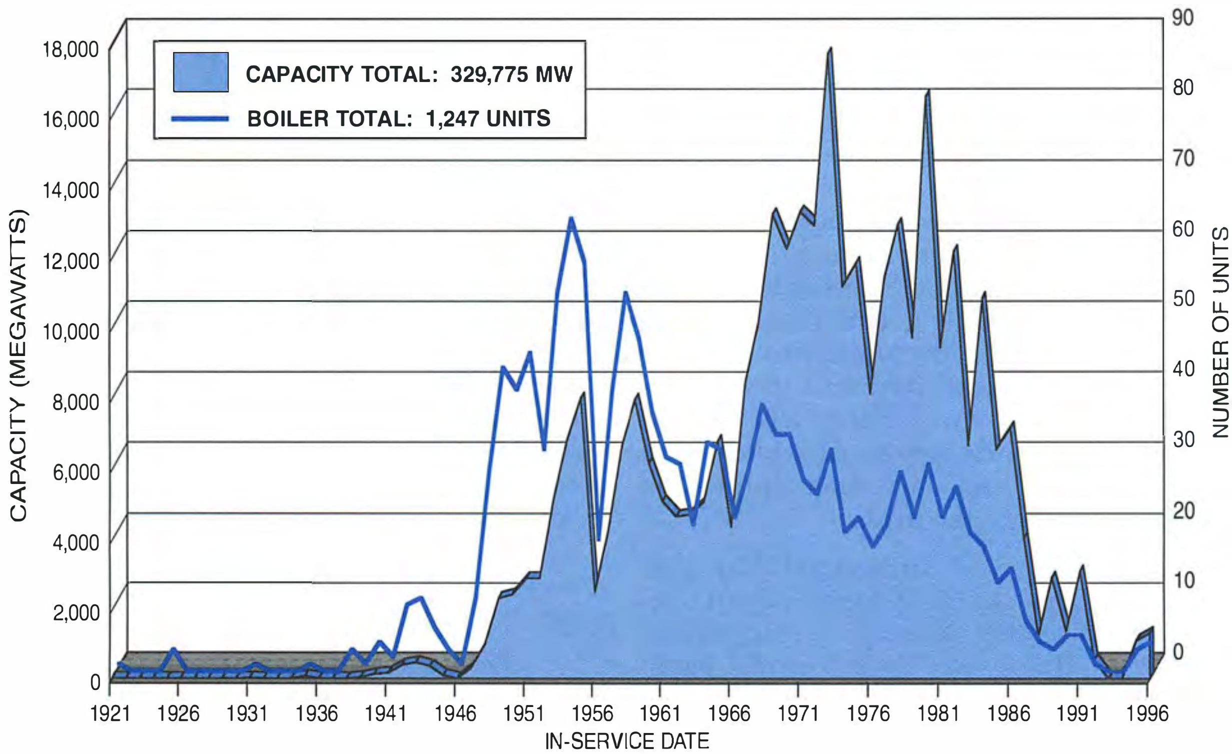
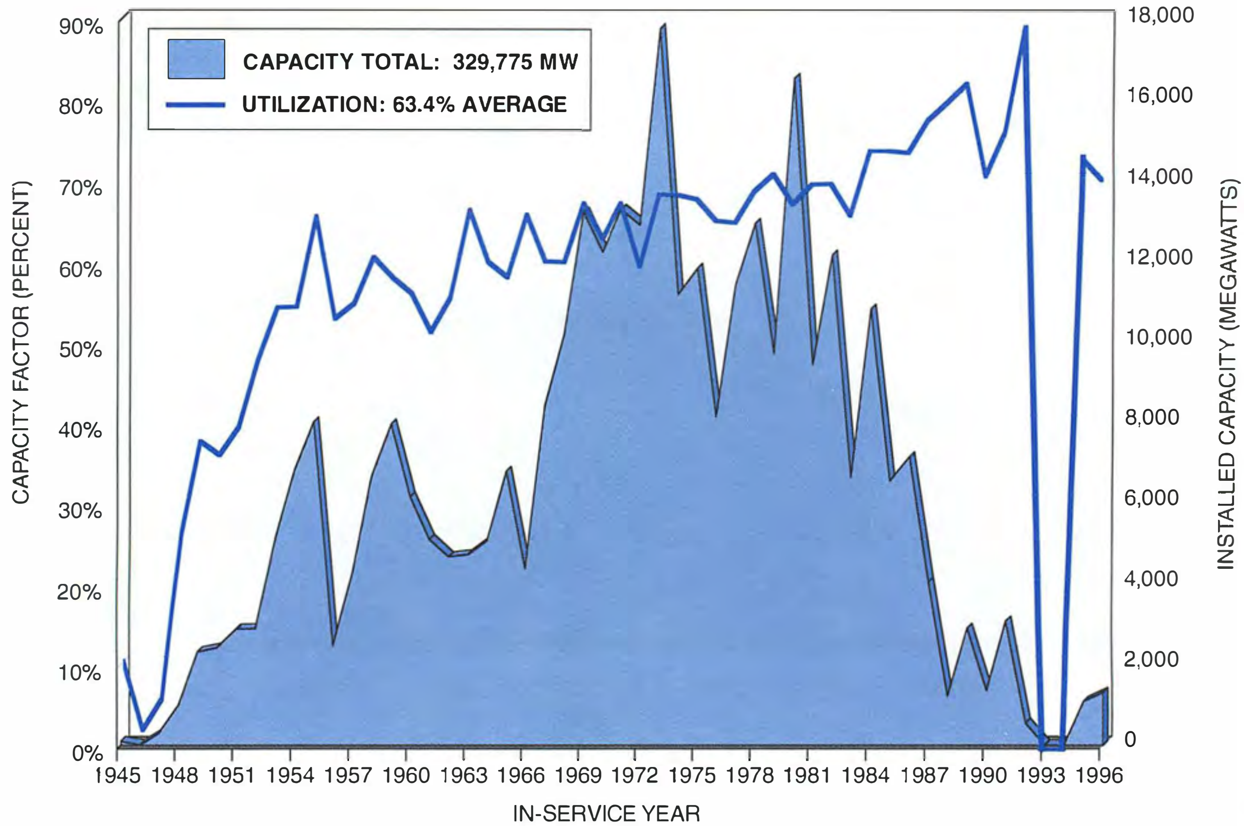


Figure D-6. 1996 Capacity Utilization Data for Coal Plants by In-Service Year



utilization rate. A 75% rate means that a plant operates 18 hours a day at full load, 365 days a year. Or, by way of additional example, it could operate at full load for 274 days and be shut down for the remainder of the year. In each case, it would be said that the plant generated 75% of its maximum potential output. When one considers *aggregated* coal-fired capacity, neither of the above examples is completely adequate in that the system does not act as a single generator and single load. Instead the load varies with the seasons, weather, time of day, and day of the week. Individual power plants will operate base-loaded for much of the year while others cycle on and off and vary their outputs as necessary to balance the load.

It should also be understood that with minor exceptions electricity loads are not constant 24 hours a day, 365 days a year. Loads on electric utilities vary on a seasonal basis; seasonal variations are caused by weather variations that impact primarily space heating/cooling and lighting loads. Electricity loads also vary substantially on an intra-day basis; intra-day variations are caused by changing temperatures, day/night changes, customer work schedules, and the like. Electricity for the residential and commercial market sectors, which account for 67% of electricity demand in the United States, drops off dramatically after 10:00 to 11:00 p.m. each night and only starts to rise after 6:00 to 7:00 a.m. each morning. It should also be understood that, with minor exceptions, electricity cannot effectively be stored, and thus it is not possible to produce electricity at night for use the following day when loads are up. The electric utility load curve is not expected to change significantly during the study period. As total electricity load expands, base load will also increase. Operators may increase coal-fired plant utilization rates in order to satisfy a portion of the expanded base load.

The issue presented by the assumption of 75% utilization is whether such a shift will in fact occur. Improvement in the utilization rate above 70% is probably a very ambitious objective. Although the subject is discussed in Chapter Three of this Demand Task Group Report, it should be noted here that a 10% decrease in the assumed utilization level of coal-fired electricity generation (i.e., from 75% to 65%) would potentially increase gas consumption by 1.7 TCF annually from the Reference Case.

It should further be noted that other disincentives for improved coal-fired plant utilization may arise due to environmental restrictions. In this connection, the Department of Justice and several state governments have recently filed suit against seven large utilities, charging that their coal-fired plants had effectively added to capacity during maintenance activities without installing new pollution equipment that would have been required if capacity had otherwise been expanded. It should also be noted that recent EPA regulations concerning installation of catalytic converters for NOx control will decrease heat rates by approximately 1% in coal-fired plants. While it is too early to calculate the effect of these measures on capacity utilization of coal-fired plants, the effect is presumably negative.

GAS

Installed capacity of gas/oil combined-cycle and gas-fired combustion turbine capacity will grow from 25 gigawatts in 1998 to 113 gigawatts in 2010 and 140 gigawatts in 2015.

Fossil-fuel-fired unit heat rates are predicted to improve 0.3 to 0.5% per year depending on generation type between 1998 and 2015. The improvement in electricity generation heat rates reflects the view that competition in electricity generation markets and improved technology will continue to "raise the performance bar" in this market segment. However, mandated addition of new exhaust equipment on coal-fired plants could push performance in the other direction.

Seventy percent of combined-cycle plants are assumed to be capable of burning either gas or oil and would therefore switch fuels depending on cost. The examination of fuel-switching capabilities of new combined-cycle plants by the Demand Task Group indicated that operating these units with distillate oil would be both technically feasible and economic given the relationship between gas and oil prices projected in the Reference Case. Under these conditions, the seasonal switching of gas-fired units to distillate oil during the winter heating season provides an opportunity for electricity generators to lower their annual operating costs while simultaneously providing residential and commercial gas customers with a source of seasonal gas supply. The effect of fuel switching is to reduce peak load growth on pipeline and gas storage systems and to lower energy costs during periods when gas prices are likely to exceed the cost of oil. It should be recognized, however, that electricity generating plants contemplating fuel switching over seasonal periods will require very substantial quantities of low sulfur distillate.

By 2015, when 140 gigawatts of gas-fired generating plants will be in operation, fuel switchers would require nearly 3,500,000 barrels per day of distillate throughout the peak month. This calculation is based on the assumption that fuel-switching plants operate on oil for an entire month. Under normal winter conditions, peaks on pipeline systems last for a few days and are followed by warmer weather and then by another peak period as another cold wave follows. As more and more gas-fired units go on line, fuel switchers will need to evaluate the need for special fuel oil contracts, additional investment in oil storage facilities, or both.

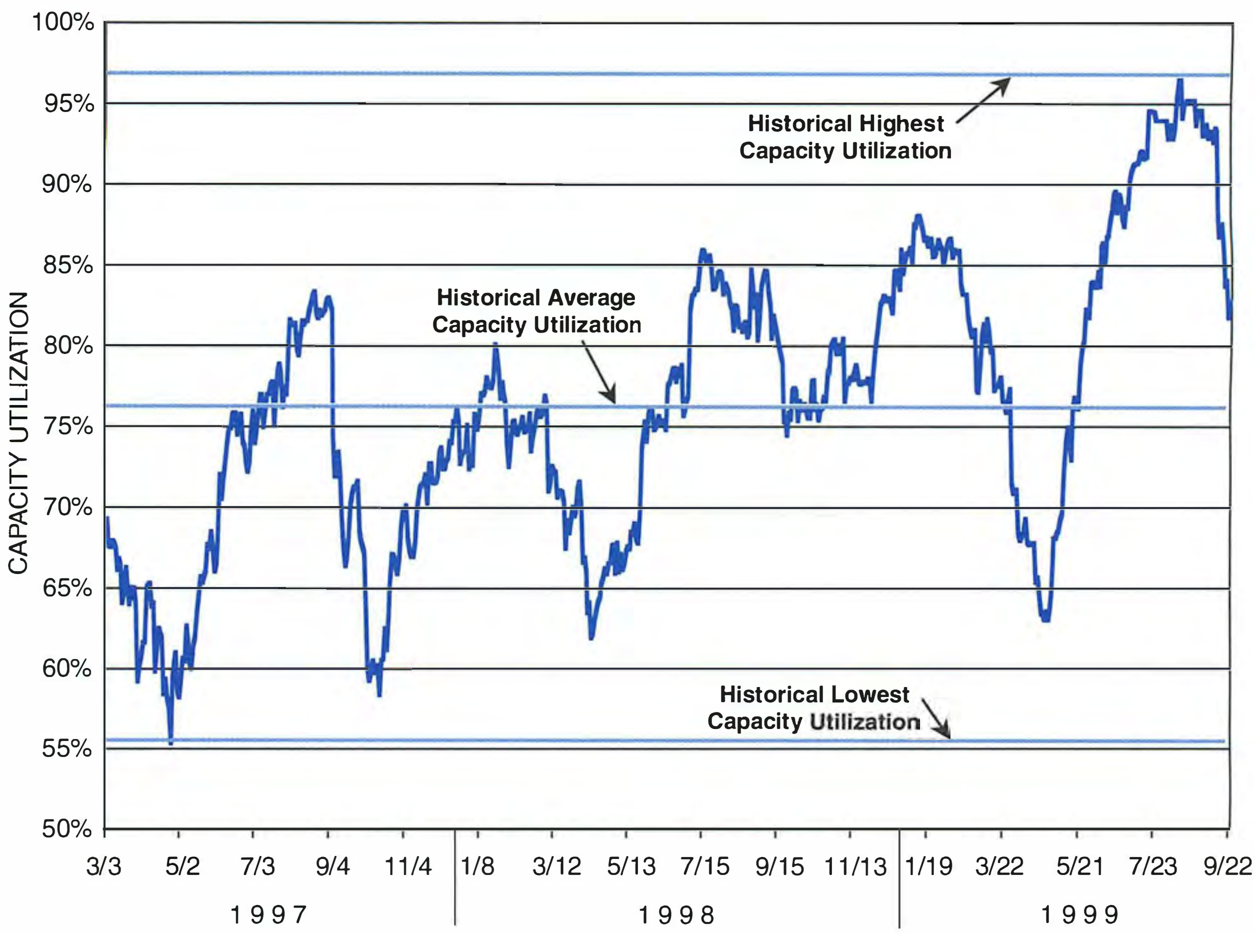
NUCLEAR

Considerable effort was devoted to the subject of nuclear capacity and its utilization. The Reference Case does not include any new nuclear capacity. The Demand Task Group studied all announced nuclear plant shutdowns and reviewed a schedule of the existing expiration dates for all licenses of nuclear plants. Installed capacity of nuclear generating plants was approximately 97 gigawatts in 1998. The problem faced by the Demand Task Group in estimating nuclear capacity during the study period centered on the re-licensing question. Licenses for 30 gigawatts of capacity are due to expire during the period to 2015. Will the owners of these plants apply for Nuclear Regulatory Commission (NRC) approval to re-license these plants to dates beyond the study period? Or will these plants simply be retired at the license expiration date? To date, no U.S. nuclear plant has ever been re-licensed. Therefore there is no precedent from which to make a forecast. The Task Group chose to make the assumption that 50% of the capacity at issue (15 gigawatts) would be re-licensed and the other 50% (15 gigawatts) would be retired at license expiration. Under this assumption, nuclear capacity of approximately 81 gigawatts would remain in operation at 2015. As noted in Chapter Three of this Demand Task Group Report, a difference of 15 gigawatts of nuclear capacity equates to approximately 0.8 TCF of additional annual gas demand. The Task Group was somewhat comforted by the fact that the bulk of the 30 gigawatts of nuclear capacity licenses at issue expire during the period 2010 to 2015, and therefore the assumptions made should be reasonably valid to 2010.

It should be noted that nuclear plant capacity utilization, which in earlier periods was very poor, has increased dramatically in recent years (Figure D-7). With the resumption of service at the Clinton, LaSalle, and Millstone units in the spring of 1999, daily nuclear capacity utilization reached an unprecedented high of 96.5% in August 1999. This figure compares with the previous daily high utilization of 86% in July 1998 and a historical average daily high of approximately 75%.

Annual capacity utilization rates for nuclear plants have increased in recent years to approximately 75%. The model projects a further increase in the nuclear utilization rate to the 80% range by 2005 continuing at approximately the same rate to 2015. Nuclear retirements in the out years beyond this study could significantly increase gas demand.

Figure D-7. Total U.S. Daily Nuclear Capacity Utilization



Source: U.S. nuclear complex activity data, *BTU Daily*.

HYDRO AND RENEWABLES

According to EIA statistics, approximately 4% of total U.S. purchased energy demand is supplied by hydro and other renewable sources. Of that total, 3.8% is supplied by hydro and 0.2% by renewables. An additional volume of energy is sourced from renewables but is not included in the total demand because industrial by-product fuel is not typically measured or reported.

Hydro generation is assumed to remain nearly constant throughout the period of the Reference Case. However, hydro generation could diminish due to environmental concerns about the adverse impact of dams on anadromous fish. Hydro dams in the United States are granted licenses by the Federal Energy Regulatory Commission (FERC, formerly Federal Power Commission). These licenses are for a stated period of years and unless re-licensed, dams must be removed on expiration of the licensing period. Several small, non-operational dams have been removed due to expiration and non-renewal of licenses. There is considerable pressure from environmental and sportsmen's organizations in favor of breaching dams that obstruct the migration of anadromous fish. Several species of anadromous fish have recently been classified as endangered.

Renewables (particularly from wood) are a larger source of energy than is generally recognized. Most renewables are consumed to make steam and electricity. Wastewood, usually sawdust from mill operations or wood chips from tops and branches removed during logging operations, has been used for many years for cogeneration and power generation purposes and undoubtedly will continue to be so used in the future. Wind power currently provides approximately 0.1% of electricity demand. Wind is growing faster than any other renewable energy source, but its growth is from a very small base.

For some time, there have been proposals concerning the use of biomass materials (other than wood) as a fuel source for electricity generation. Technological progress in this area may indeed make such biomass economically competitive with fossil fuels. The Demand Task Group is not aware of currently available technology that would make such fuels economically feasible. Therefore, it did not assume an increase in electricity generation from renewables. If renewables do develop more rapidly than anticipated, the resulting error may be offset by a decline in hydro. In any event, the error will occur in the out years of the study and corrections can be made in subsequent NPC natural gas studies.

Weather

Actual heating degree days (HDD) and cooling degree days (CDD) were used through February 1999; weather was assumed to be "normal" thereafter. HDDs are calculated by subtracting the mean temperature on any day from 65 degrees Fahrenheit. (It is assumed that heating is not required on a day on which mean temperature is above 65 degrees.) Thus, a day on which the mean temperature was 30 degrees would have 35 HDDs. CDDs are calculated by subtracting a base of 75 degrees Fahrenheit from the mean temperature on any day. Thus, a day on which the mean temperature was 90 degrees would have 15 CDDs. The foregoing definitions of HDDs and CDDs are widely accepted in the utility industry. Individual companies sometimes vary the definition for proprietary estimates of load sendout. Normal weather is defined as the population-weighted average of HDDs and CDDs for the 1961 to 1990 period.

Factors Not Included in Assumptions

After careful consideration, the Demand Task Group decided *not* to make assumptions concerning a number of matters that it reviewed.

Technology

As noted above, the Demand Task Group did include technological progress concerning fossil fuel heat rates for electricity generation. The Task Group did not include the effects of other new and important downstream technologies because it believed the net effect of these technologies was difficult to quantify. (The Supply Task Group performed a sensitivity analysis of the impact of improved upstream technologies.)

As an example of the complexity of analyzing downstream technology, many experts believe that distributed generation by means of micro-turbines or fuel cells will experience considerable growth between now and 2015. Essentially, "distributed generation" is electricity generation produced by relatively small generating units located within the electricity distribution network and typically at the consumption site; the alternative to distributed generation is central plant generation involving large generating units connected to customers by transmission and distribution lines. The Reference Case assumes very limited penetration of distributed electricity generation technologies. The Task Group recognizes that improvements in distributed generation technologies and changes in electricity pricing structures, combined with potential bottlenecks in electricity transmission capacity, could result in significant market penetration of distributed generation. Growth in distributed generation could significantly increase the percentage of gas sold or transported by local distribution companies (LDCs) for electricity generation.

While distributed generation might increase gas demand in the residential and commercial segments as customers in these segments purchase generation equipment, such growth would probably be offset by a decline in gas demand for electricity generation at central plants. At this point, it is not clear whether gas-fired generation would back out natural gas or coal at central generating stations. While a 1:1 relationship between gas demand for distributed generation and backed out gas demand at central generation stations probably does not exist, the net error is probably too small to be relevant in the context of total gas demand.

Environmental and Regulatory

The demand estimates do not include the effect of future environmental and other regulations, such as the effect of complying with the Kyoto protocol. EIA and the Edison Electric Institute have conducted separate studies of the impact of meeting the U.S. target under the Kyoto protocol. These studies confirm that substantial reductions in coal and oil consumption would be required with a concomitant increase in gas demand. These studies examine various scenarios and indicate an increase in gas demand of 2–12% in the case of EIA, and 10–22% in the case of Edison Electric Institute. The indicated increase represents an increment above demand levels that would otherwise prevail.

Chapter Two

Gas Demand Projected by Current Study

As a necessary prelude to the projection of future gas demand, it is necessary to look at the growth in both U.S. and Canadian gas demand for the 1987–98 period (see Table D-3). Compound growth rate for U.S. consumption for the 1987–98 period was 1.9%; for Canada during the same period, 2.9%. Growth in gas demand flattened in 1997 and 1998 as a result of mild winter weather in both years.

Employing the assumptions discussed in the preceding chapter, the model estimates that U.S. gas consumption will increase from 22 TCF in 1998 to 29 TCF in 2010 and around 31 TCF in 2015 (see Figure D-8). Table D-4 shows the breakdown of consumption by end-use categories. North American gas consumption for the same period is shown in Table D-5. (See Appendix C and the CD-ROM for detailed results of the reference and sensitivity cases.)

It should be noted that—consistent with the form of EIA reports—the 1999 Study nets gas exports to Mexico against gas imports and reports the net amount in the supply tables. An alternative method would have been to report Mexican exports, most of which is gas used for electricity generating projects in areas of Mexico contiguous to the United States, as additional demand.

Compound growth rates for both U.S. and Canadian consumption projected to 2010 and to 2015 are set forth in Table D-6. The 1998 data included a significantly warmer than normal winter, which masks the underlying growth in residential and commercial space heating demand for the historical period. (Also see textual explanation of Table D-1

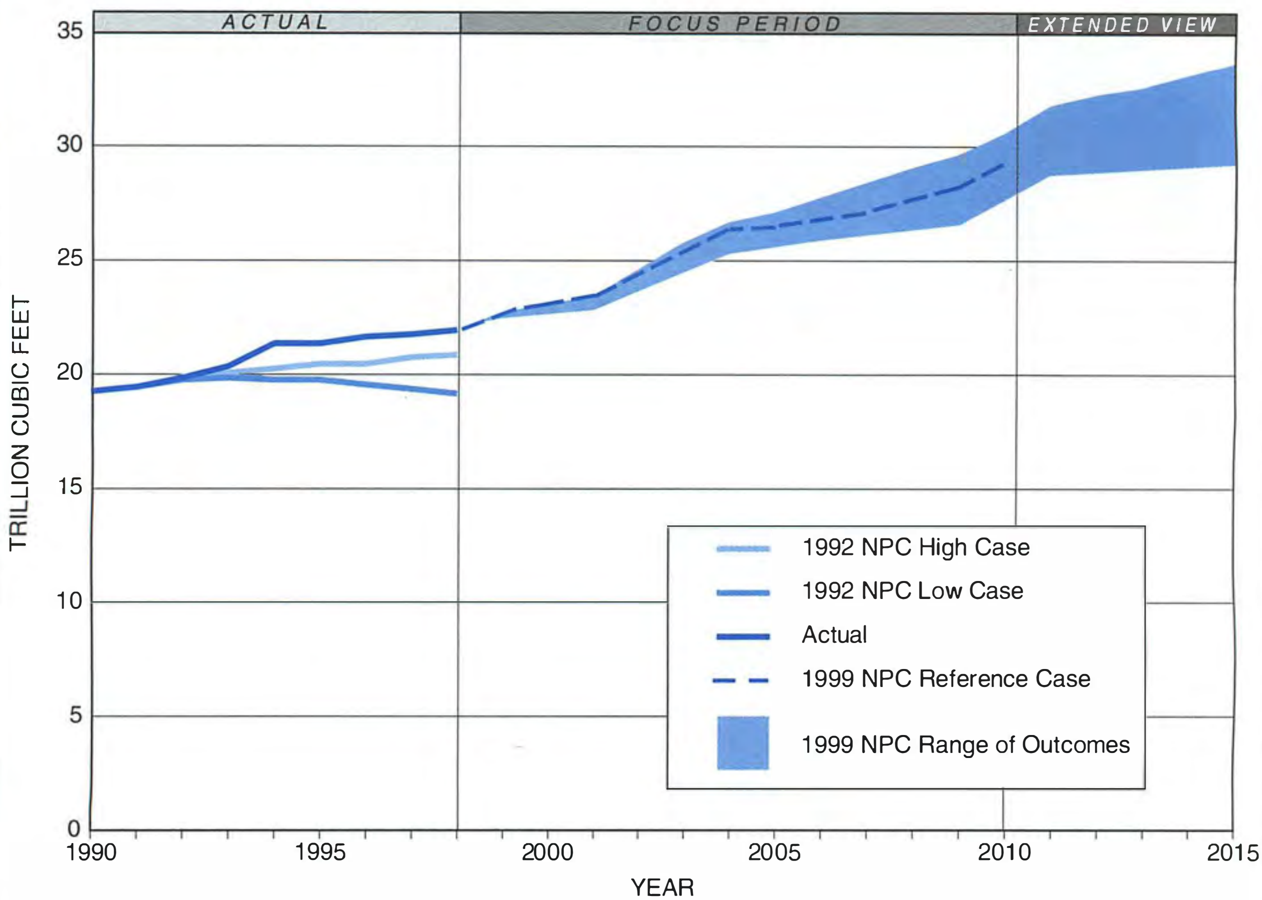
TABLE D-3

CANADIAN AND U.S. GAS CONSUMPTION 1987 THROUGH 1998 (Trillion Cubic Feet per Year)

Year	Canadian Gas Consumption	U.S. Gas Consumption
1987	2.08	17.26
1988	2.31	18.04
1989	2.46	18.85
1990	2.34	18.77
1991	2.37	19.08
1992	2.57	19.58
1993	2.68	20.26
1994	2.84	20.71
1995	2.86	21.56
1996	3.04	21.91
1997	2.85	21.7
1998	2.85	21.3

Source: U.S. Department of Energy and the National Energy Board of Canada.

Figure D-8. U.S. Natural Gas Demand
Comparison of 1992 and 1999 NPC Study Results



Source of historical data: DOE/EIA, *Natural Gas Monthly,* September 1999.

TABLE D-4

U.S. NATURAL GAS CONSUMPTION
(Trillion Cubic Feet)

	1998	2005	2010	2015
Total Consumption	22.0	26.3	29.0	31.3
Total End Use	19.4	24.0	26.4	28.7
Residential	*4.5*	*5.6*	*5.8*	*6.1*
Commercial	*3.0*	*3.7*	*3.8*	*4.1*
Industrial	*8.6*	*9.6*	*10.2*	*10.8*
Electricity Generation	*3.3*	*5.1*	*6.6*	*7.8*
Lease, Plant, & Pipeline Fuel	2.0	2.2	2.5	2.5
Net Storage Fill/Balancing	0.6	0.1	0.1	0.0

Source: Energy and Environmental Analysis, Inc.

TABLE D-5

U.S. AND CANADIAN NATURAL GAS CONSUMPTION
(Trillion Cubic Feet)

	1998	2005	2010	2015
Total Consumption	24.2	29.6	32.5	35.2
Total End Use	21.8	26.7	29.4	31.8
Residential	*5.1*	*6.2*	*6.5*	*6.8*
Commercial	*3.4*	*4.2*	*4.4*	*4.6*
Industrial	*10.1*	*11.3*	*12.0*	*12.7*
Electricity Generation	*3.2*	*5.1*	*6.6*	*7.8*
Lease, Plant, & Pipeline Fuel	2.4	2.8	3.1	3.2
Net Storage Fill/Balancing	0.0	0.2	0.1	0.0

Source: Energy and Environmental Analysis, Inc.

TABLE D-6

NATURAL GAS CONSUMPTION
COMPOUND GROWTH RATES

	1990-98 Actual	2010 Forecast	2015 Forecast
Residential	*0.1%*	*2.1%*	*1.7%*
Commercial	*1.2%*	*2.2%*	*1.9%*
Industrial	*2.7%*	*1.4%*	*1.3%*
*Electricity Generation**	*1.7%*	*6.1%*	*5.3%*
U.S. End-Use Total	1.9%	2.6%	2.3%
Canadian End-Use Total	2.5%	1.8%	1.7%

*Industrial volumes through 1998 include consumption of gas for non-utility generation, which grew rapidly in the early 1990s. After that date, the model reclassifies gas used in new generating plants (whether utility or non-utility) as "Electricity Generation." Existing non-utility plants as of 1998 remain classified as "Industrial."

Source: Energy and Environmental Analysis, Inc.

data in Chapter One of this Demand Task Group Report.)

Largest Growth in Demand is for Electricity Generation

The most significant growth in gas demand is estimated to be for electricity generation. In the 1992 Study, increased penetration of the electricity generation market was an objective. Today—as a result of a dramatic improvement in heat rate for combined-cycle gas/oil generating stations, the relatively low capital cost of such plants, the relatively short construction time required to bring them on line, tighter emission standards for electricity generation, and the deregulation of electricity generation—gas is virtually the *sole choice* of the electricity generating industry for new electricity generating plants. Currently, 98% by capacity of the 243 electricity generating plants that have been announced for construction in the next five years are to be gas-fired; the remaining 2% by capacity will be fueled by coal, oil, wastewood, wood, wind, and other (Table D-7). Assuming that the indicated gas-fired plants are all built, gas-generated electricity would increase to approximately one-third the theoretical capacity (330 gigawatts) of coal-fired plants.

TABLE D-7

PLANNED ELECTRICITY GENERATION PLANTS

	No. of Plants	Total Megawatts
Fossil-Fueled		
Gas-Fired	202	102,588
Coal-Fired	10	553
Oil-Fired	2	477
Total Fossil-Fueled	214	103,618
Renewables		
Wastewood-Fired	3	69
Wood-Fired	2	67
Wind	17	477
Total Renewables	22	613
Other	7	168
Total All Plants	**243**	**104,399**

Source: Online data base at Resource Data International, Inc. (July 1999), except wind data. Wind data from American Wind Energy Association web site.

It is highly significant that electricity generators have changed their attitudes radically toward gas-fired generation since the 1992 Study. The price of coal increases fractions of a single percent per year. The price of gas is highly volatile and routinely swings up and down 50% during the course of a year. Notwithstanding volatility, five circumstances have led to the choice of natural gas as the preferred fuel for new generating stations. One, the heat rate[1] on combined-cycle gas generating plants gives gas a strong economic advantage. Two, the capital cost of a combined-cycle gas-fired plant is approximately \$500 to \$650 per megawatt, compared to \$1,000 to \$1,500 per megawatt for coal-fired plants. Three, the construction time for combined-cycle plants is approximately two years versus five to seven years for coal-fired plants. Four, in a deregulated environment, electricity generators seek the shortest possible time between the decision to build and point at which capital costs are recovered. Gas-fired plants have the shortest construction time. Five, it is far easier to obtain permits for new combined-cycle gas plants than for coal-fired plants.

As a result, by 2010, gas use for electricity generation will account for 47% of the incremental gas demand projected in the Reference Case. The growth in relative importance of electricity generation results from the retirement of nuclear capacity and the dominant position of gas as the fuel of choice for newly constructed generation capacity. After 2010, however, the dominance of gas could be challenged as cost comparisons of coal and other alternatives vs. natural gas improve. It should be noted that the assumptions used in the Reference Case assume that the utilization rate of coal-fired plants will improve significantly over the study period. Many knowledgeable observers, though accepting the economic rationale for increased utilization, question whether existing coal-fired plants are physically capable of operating at the higher levels assumed. If not, natural gas usage will have to meet the gap.

It should also be noted that although predicted electricity demand is derived from the model, electricity growth could rise faster than the predicted rate. The model predicts the annual growth rate will be 2.3%. Some observers believe that growth in the Internet may increase electricity consumption beyond

[1] Heat rate is a measurement of the amount of thermal energy consumed in producing electricity, expressed in Btu of energy input per kilowatt-hour generated. For example, the heat rate of modern combined-cycle electricity generating plants is approximately 7,000 Btu per kilowatt-hour, representing an efficiency of nearly 50%. Modern coal-fired plants have a heat rate of approximately 10,000 Btu per kilowatt-hour, representing an efficiency of roughly 34%.

the predicted levels. It should be noted that net U.S. electricity generation increased from 3,494,441 million kilowatt-hours in 1997 to 3,619,632 million kilowatt-hours in 1998, or 3.6%.[2] Trends in electricity consumption should be actively monitored as an early warning indicator of potential error in the study forecast.

Although the precise level of increased demand for electricity generation is subject to some debate, the total under any scenario is very large. The Reference Case projects an additional gas demand of 3.9 TCF by 2010 for electricity generation. *It is critical for the gas industry to recognize that the increased demand for gas for electricity generation is no longer just potential—it's a fact.* The supply side of the industry and the transmission and distribution segment must begin planning now to meet this new load.

Growth in Peak Demand

Continued growth—albeit at a slow rate—in the traditional residential, commercial, and industrial applications will lead to a growth in peak demand. The space heating load, as has historically been the case, will establish new peaks. Peak-day demand requirements are projected to grow in the Reference Case by 29% by 2010. Assuming that most operators of combined-cycle gas/oil plants switch to oil on the basis of price differentials fuels during peak periods, gas demand for electricity generation is likely to fall in the "valley" between seasonal peaks. This subject is discussed at greater length in the report of the Transmission & Distribution Task Group.

Sector Analysis

It is useful to break down the growth in gas demand by sectors in order to understand some of the factors that are driving the market for gas to 2010 and 2015.

Residential

From 1992 to 1997, gas consumption in the residential sector grew from 4.7 TCF to 5.0 TCF, or a compound annual rate of 1.3%. Residential gas consumption is estimated to increase from 4.5 TCF in 1998 to 5.8 TCF in 2010 and 6.1 TCF in 2015, or a compound annual rate of 2% to 2010 and 1.7% to 2015. The principal uses of gas for residential purposes are cooking, water heating, space heating, clothes drying, and air conditioning. According to the 1998 EIA report, *Residential Energy Consumption Survey*, space heating is by far the largest use, accounting for 51% of energy demand and 68% of natural gas use in U.S. households. For this reason, variations from normal winter weather can substantially increase or decrease natural gas demand in any year. Natural gas competes with electricity for each of these uses. Oil has a significant share of the space heating market in the Northeast. Liquefied petroleum gas (LPG) is used for the same purposes; LPG users are typically found in areas beyond the reach of the gas distribution grid. Of the total fuel used in the residential sector in 1998, 45% is estimated to be natural gas, 37% electricity, 12% fuel oil, and 6% other. These numbers exclude the energy input required to create purchased electricity.

In terms of market penetration in particular end uses, natural gas is estimated to enjoy the market shares shown in Table D-8. The gas industry continues to serve the majority of new space-heating customers. Due to a growing economy and the increased number of households, the number of gas customers is projected to increase from 60.5 million in 1998 to 71.5 million in 2010 and 76 million in 2015.

Net growth in the residential sector is the result of several contrasting trends. On the one hand, U.S. housing stock is expected to grow 1.3% per annum (including multi-family). These numbers compare with an annual growth rate of 1.5% in the years 1993 through 1997. Total U.S. housing stock at December 31, 1997, is estimated at 101.6 million units, an increase from 90.5 million units a decade earlier. Increases in housing stock obviously result in increased demand for natural gas. It should be noted that gas space heating also increases electricity consumption for fans and pumps to distribute heat within the dwelling unit. Although gas-heated housing units are projected to increase roughly 50% to 2015, residential gas consumption grows by 22%. This apparent disparity is due in large part to improvement in

[2] Energy Information Administration, *Electrical Power Annual 1998*, Vol. I, p. 5.

TABLE D-8

1998 MARKET SHARE RESIDENTIAL END USES (Thousands of Btu)

End Use	Gas	Electricity	Oil	Other
Cooking	155.5	135.7	22.6	0
Water Heating	1,322.2	529.8	140.5	0
Space Heating	2,938.2	748.9	1,002.7	667.2
Clothes Drying	61.1	171	0	0
Air Conditioning	6.8	754.8	0	0
Other	132.2	1,484.7	78	
Total	**4,616**	**3,835**	**1,243.8**	**667.2**

furnace efficiency in both existing and projected housing stock.

Because of better insulation and other construction practices and high-efficiency furnaces, new construction is more fuel efficient than the average home in the nation's housing stock. The efficiency rate of new furnaces installed in residential construction has increased from an estimated 78% in 1992 to 84% in 1997. Average installed furnace efficiency has been estimated by the American Gas Association to be between 60% and 65%. Current NAECA (National Appliance Energy Conservation Act) standards prohibit the manufacture and sale of furnaces with an efficiency of less than 78%. The model assumes that furnace efficiency will continue to improve as new construction becomes a bigger proportion of the nation's housing stock and as older furnaces are replaced with new, high-efficiency equipment. These trends tend to reduce residential demand.

On the other hand, new homes tend to be larger than the average house; more square feet translate into increased demand. "Large" homes (over seven rooms) increased from 21.7 million in 1987 to 29.4 million in 1997. "Small" homes (four rooms or less) grew by only 0.7% per year in the same period. Pushing in the other direction, however, new construction is disproportionately located in the South and West, where space-heating requirements are lower than in the North. And the addition of new air conditioning units for homes built in the South will tend to increase the demand for natural gas as a primary fuel for incremental electricity generation. Average annual gas consumption per single family home is about 79.4 thousand cubic feet (MCF) per unit. In the Midwest and Northeast, the consumption rate is 94.9 MCF and 88.7 MCF, respectively. In the South and West, the consumption rate is 63.1 MCF and 69.8 MCF, respectively.

Although residential volume is expected to grow only 1.6 TCF over the period to 2015, LDCs will be required to invest substantial sums in new mains and service lines to serve a very large increase in the number of residential customers. Since the space heating load falls on (and indeed creates) the peak day, pipelines will also be required to invest in additional transportation and storage facilities. (See the Transmission & Distribution Task Group Report.)

Commercial

Between 1992 and 1997, commercial gas consumption grew from 2.8 TCF to 3.2 TCF, or a compound annual growth rate of 2.7%. Gas use in the commercial category is estimated to grow from 3.0 TCF in 1998 to 4.3 TCF in 2010 and 4.5 TCF in 2015, or a compound annual growth rate of 3.3% to 2010 and 2.6% to 2015. The Commercial category covers a wide range of business types, including restaurants, hotels, and office buildings. Commercial consumption broken down by end use is shown in Table D-9.

TABLE D-9

COMMERCIAL SALES VOLUMES 1998

End Use	BCF	Percentage of Total
Space Heating	1,650.5	53.9%
Space Cooling	120.1	3.9%
Water Heating	447.1	14.6%
Cooking	330.7	10.8%
Drying	174.6	5.7%
Other	186.6	6.1%
Power Generation	155.3	5.1%
Cogeneration	*151.9*	*5.0%*
Other Generation	*3.3*	*0.1%*
Total	**3,064.8**	**100.0%**

Source: Energy Information Administration, AEO2000 Forecasting System.

Like the residential market, a majority of commercial gas consumption is for space heating (54%). For this reason, growth in the commercial market will add to peak-day requirements and will necessitate additional investment by LDCs and pipelines. Water heating accounts for 15% of commercial gas sales; cooking, 11%; drying, 6%; and cogeneration, 5%. Commercial air conditioning has made considerable progress in recent years and now accounts for 3.9% of the commercial market. Commercial gas air conditioning plays a useful role in building off-peak, summer load.

In general, drivers of commercial gas demand are the growth in the service economy and growth in the square footage of commercial buildings. As in the case with residential, commercial applications are becoming more and more fuel efficient. High-efficiency ovens and stoves have been introduced for commercial cooking. These and other improvements in food service appliances have contributed to the intense competition between gas and electricity in the commercial sector. Finally, improvements in gas-fired cooling and desiccant technology have contributed to increased gas use in the commercial sector.

Industrial

From 1992 to 1997, gas consumption in the industrial sector grew from 7.5 TCF to 8.6 TCF, or a compound annual rate of 2.8%. Industrial gas consumption is estimated to increase from 8.6 TCF in 1998 to 12.4 TCF in 2010 and 13.0 TCF in 2015, or a compound annual rate of 2.5%. Problems arise in making comparisons between years because of changes in the categorization of gas used by non-utility generators. See the discussion of this subject in Chapter One of this Demand Task Group Report.

Natural gas is widely used across most industries from mining to manufacturing. The chemicals industry is the largest consumer of gas, accounting for 33% of industrial gas consumption in 1998. The next largest industrial gas users are the petroleum refining (11%), primary metals industry (8%), food (7%), paper (6%), and the stone/clay/glass industries (4%). Figure D-9 shows industrial gas use by type of industry.

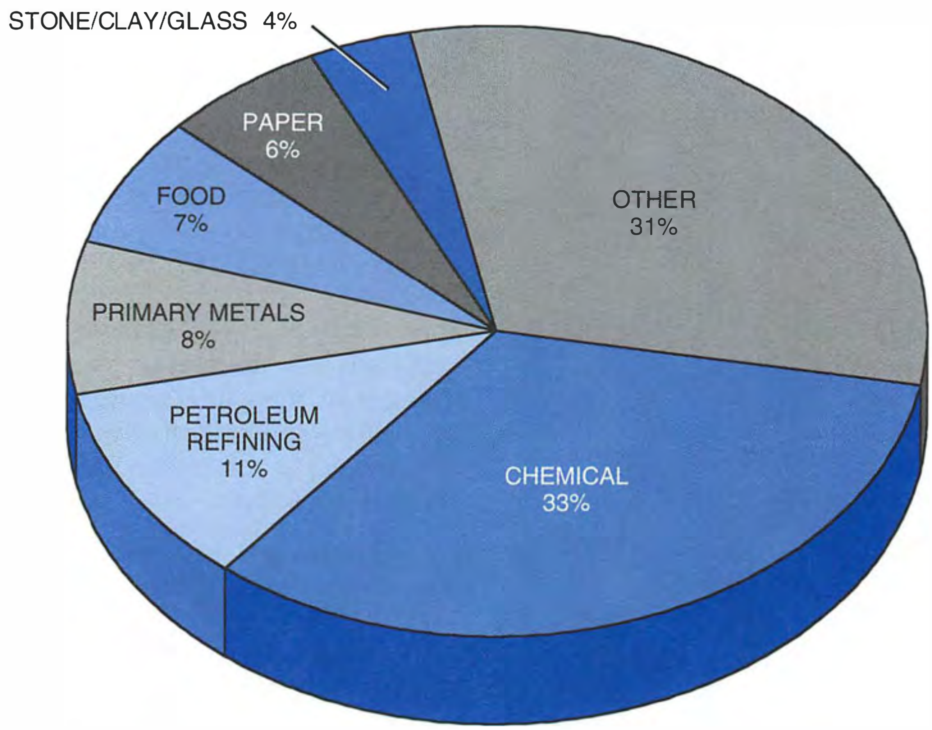
The industrial gas market is large, highly diverse, and highly competitive. Gas is used in the industrial sector for process heating, process steam, and directly as a feedstock. Gas competes for the industrial load with fuel oil, electricity, coal, and LPG. In 1998, gas market share for industrial fuels was estimated to be 40%, with 36% for fuel oil (including distillate, residual, and other liquid hydrocarbons), 14% for electricity, and 9% for coal.

The key drivers of industrial demand are the level of economic activity, as represented by industrial production, and the price of gas and alternative fuels. Projected industrial gas consumption is derived econometrically based on historical data.

Electricity Generation

As has been repeatedly noted, the largest growth in gas demand to 2010 and 2015 will be in electricity generation. Consumption for this category is projected to grow from 3.2 TCF in 1998 to 6.6 TCF in 2010 and to 7.8 TCF

Figure D-9. Industrial Gas Use by Type of Industry



in 2015. Annual rate of growth in this category is 6.6% to 2010 and 5.4% to 2015.

Clearly, environmental regulations have been one of the motivations leading electricity generators to select gas as the fuel of choice for new electricity generating plants. But economics will be the prime motivator at least until 2010. Gas combined-cycle electricity generating plants have a heat rate of approximately 7,000 Btu per kilowatt-hour compared to 10,000 Btu per kilowatt-hour for coal-fired units. The Demand Task Group assumed that after 2010 some coal-fired plants would again be built as technology or economics alter the economics of fuel selection.

The construction time for gas combined-cycle plants has been as low as 18 months. Because of the demand for these units, the world's principal manufacturers of these plants now have an increasing backlog, with the result that construction time is stretching out to 24–30 months. However, construction time for a greenfields coal plant is estimated to be 5–7 years depending on permitting problems. The long lead time for construction of coal-fired plants means that absent a change by 2003 in the competitive relationships between electricity from gas and electricity from coal, a new coal-fired plant could probably not be placed in service prior to 2010. Currently, 98% by capacity of the 243 electricity generating plants that have been announced for construction in the next five years are to be gas-fired; the remaining 2% by capacity will be fueled by coal, oil, wastewood, wood, wind, and other (see Table D-7).

There can be no doubt that deregulation of electricity generation has hastened the move to natural gas. Utility and non-utility generators now compete on a level playing field; the name of the game is cost per kilowatt-hour generated. With gas combined-cycle plants having a cost advantage, there is a rush by both types of generators to put combined-cycle plants in service. The relatively short construction time for gas combined-cycle plants allows an owner to put a plant in service in time to take advantage of this cost advantage and recover a substantial portion of its investment in the plant during the early years when projected economics are most likely to hold true.

With acute competition expected to develop among electricity generators and the resulting potential for surplus generating capacity to be constructed, it is imperative for an owner to go on line and contract to sell his output before a possible surplus can develop.

Finally, coal-fired plants have serious permitting problems. Various environmental agencies have imposed restrictions on emissions of various combustion products. These restrictions are scheduled to take effect at varying points during the study period. Without getting into the details, it is sufficient to note that permitting of coal-fired plants is becoming more difficult and the cost of compliance will add to capital and maintenance costs of coal-fired plants.

Non-End Use Demand

There are two other significant uses of natural gas that should be considered: lease and plant, and pipeline. Neither involves an end use in the United States, but each requires a brief explanation.

LEASE AND PLANT

Lease and plant use is estimated to rise from 1.2 TCF in 1998 to 1.6 TCF in 2010 and 1.8 TCF in 2015. Lease use refers to gas that is produced from wells but consumed on the lease in connection with oil and gas operations on the lease. The volume of lease use is generally a function of production and rises and falls with production. In making its estimate, the Demand Task Group assumed that lease use grows proportionately with oil and gas production.

Plant use refers to (1) gas consumed in processing gas in order to remove from the gas stream certain marketable products (such as propane, ethane, and other liquids) and undesirable constituents of natural gas (such as carbon dioxide, sulfur, entrained water, and the like) and (2) that portion of the gas stream comprising the removed products. The volume of plant use is generally a function of the volume of production, but also depends on gas quality in different fields.

PIPELINE

Pipeline use is expected to rise from 0.7 TCF in 1998 to 0.9 TCF in 2010 and remain at the same level for 2015. Long-distance transportation of gas requires the operation of compressors located every 150–200 miles along the pipeline. The most economical source of fuel for these compressors is the natural gas being transported. Pipeline use is a function of gas transported and rises or falls with throughput/mile.

Regional Analysis

As in the case of the sector analysis set forth above, demand can also be analyzed on a regional basis (Table D-10). Natural gas demand will increase throughout the forecast period in every region. The largest absolute increases in demand take place in the South Central, Mid-Atlantic, and Midwest regions, which account for nearly 50% of total growth between 1997 and 2015. In relative terms, the fastest growth is

TABLE D-10

REGIONAL DEMAND ANALYSIS*
REFERENCE CASE
NATURAL GAS DEMAND
(Trillion Cubic Feet)

	1997	2010	2015
New England	0.6	0.9	1.0
Mid-Atlantic	3.2	4.3	4.7
South Atlantic	0.7	1.0	1.1
Florida	0.5	1.0	1.1
East South Central	1.1	1.4	1.5
Midwest	3.5	4.4	4.7
Upper Midwest	0.7	1.0	1.1
Central	0.7	0.9	0.9
South Central	6.7	8.4	8.9
Southwest	0.4	0.5	0.6
Mountain	0.6	0.9	1.0
West North Central	0.1	0.2	0.2
Northwest	0.5	0.7	0.8
California	1.9	2.6	3.0
Offshore Shelf	0.2	0.2	0.1
Offshore Slope	–	0.2	0.2
Canada	2.9	3.5	3.8
Alaska	0.4	0.5	0.6

*Excludes Mexican Exports.

Source: Energy and Environmental Analysis, Inc.

expected to occur in the Florida, New England, Mountain, and Mid-Atlantic regions, where growth will increase faster than 2.3% per year between 1997 and 2010.

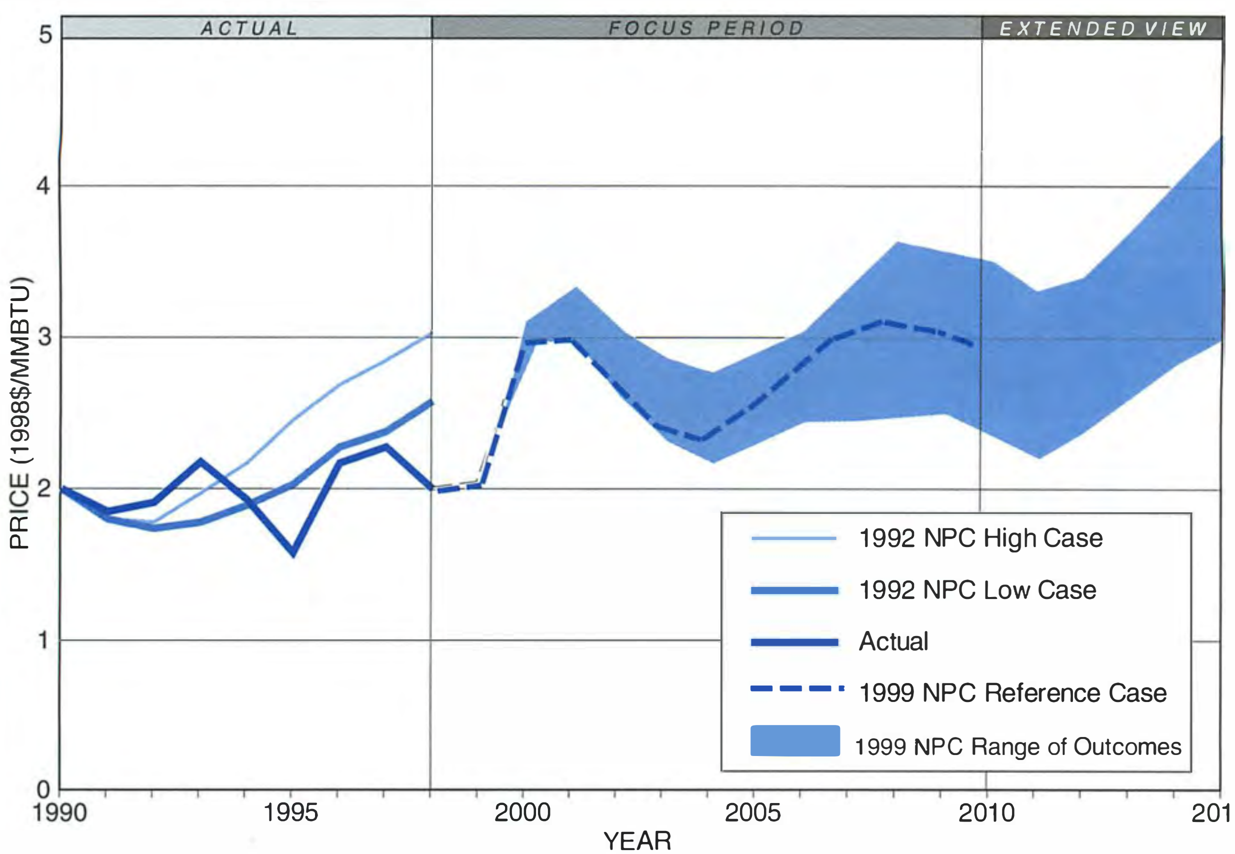
Gas Price

In a market economy, price is always the point at which supply and demand balance. Gas price is not an assumption in the model but a product of the model. Gas prices for the study period were derived by running the model using the assumptions discussed herein. Gas demand was adjusted by the model for fuel switching, primarily in electricity generation and industrial applications, based on the relative prices of gas, oil, and, potentially, coal. Fuel-switching forecasts are based on patterns of least cost dispatching of electricity generating units built into the model. (See discussion of least cost dispatching in Appendix H.) The results of the model runs are shown in Figure D-10. It is important to remember that in the Reference Case oil price, unlike gas price, is based on an assumed price of $18.50/bbl that remains constant throughout the study period.

It should be noted that projections of price, whether of oil or natural gas, are notoriously unreliable at any particular point in time. Although long-term price trends are reasonably predictable from the model, price at any point in time reflects variables, such as seasonal weather, supply disruptions due to hurricanes, and many other factors. Macro factors also disrupt long-term price movements. In Figure D-10, note the variation from actuals in the prices forecast by the 1992 Study.

Figure D-10. Historical and Projected U.S. Natural Gas Prices*

Lower-48 Weighted Average Wellhead Price



* *Prices are NOT intended to be a forecast. Seasonal factors such as abnormal weather and demand fluctuation have not been taken into account.*

Source: DOE/EIA, *Monthly Energy Review*, September 1999.

Chapter Three

Sensitivity Analyses

The Demand Task Group developed sensitivity analyses—or "delta" analyses—to evaluate the impact of key assumptions on gas demand in the Reference Case. In the following scenarios, all assumptions in the Reference Case remain the same except those specifically mentioned in the delta cases. Oil price references are to WTI. Figure D-11 illustrates the effect on demand of various key sensitivities.

Electricity Generation Sensitivities

The largest potential delta in the demand study involves the assumptions made concerning electricity generation. The two critical assumptions, both of which were subject to debate among members of the Demand Task Group and which are discussed in greater detail in Chapter Two of this Demand Task Group Report, are as follows:

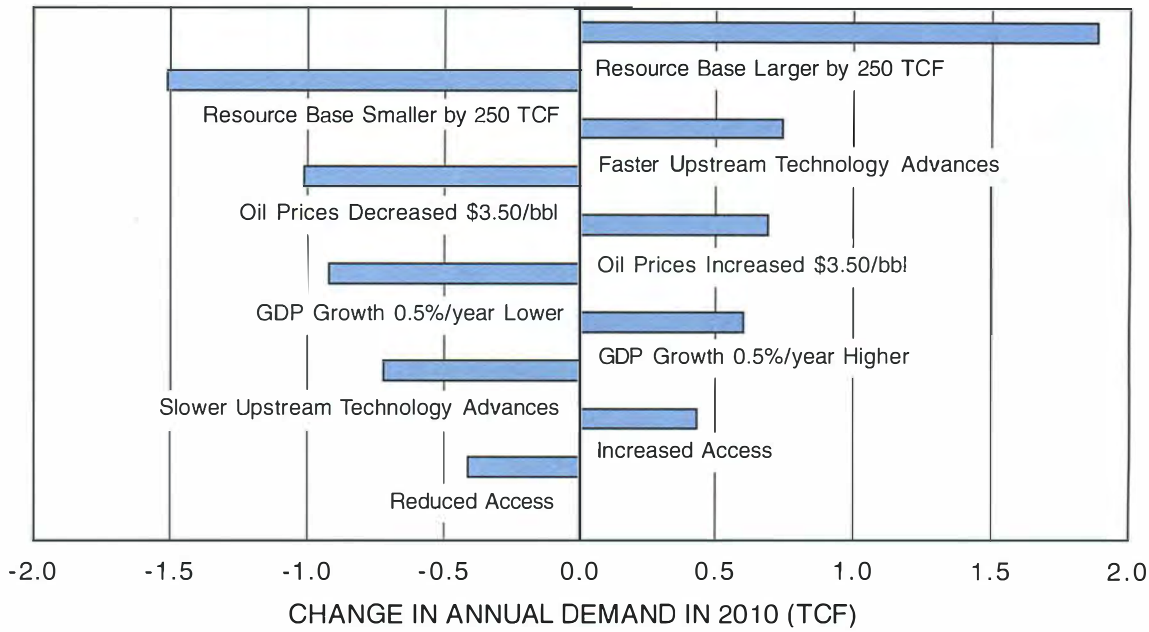
- The assumption that coal-fired plant utilization will increase 11 percentage points from 64% in 1997 to 75% by 2010
- The assumption that only 15 gigawatts of nuclear generation capacity will be retired by 2015 as licenses expire.

The Demand Task Group continues to believe that the assumptions used in the Reference Case are reasonable, but recognizes that its judgment is primarily based on economics. In fact, in addition to economics, both assumptions involve certain non-economic factors that are difficult to assess from a 1999 perspective.

In the case of coal-fired plant capacity utilization, the primary uncertainty lies in whether utilization can be improved by 11%, from 64% to 75%. The subject of coal-fired plant capacity utilization was discussed in the preceding chapter. As stated earlier, it is not clear that an 11% improvement in capacity utilization of coal-fired plants can be achieved. A sensitivity analysis indicates that a 10% decrease in capacity utilization from the assumed rate of 75% (i.e., coal-fired capacity utilization holding at 65%) would increase gas demand for electricity generation by 1.7 TCF annually from the Reference Case. A 1.7 TCF increase in gas demand for electricity generation would represent a 26% increase in the volume of gas demand forecasted for that use in 2010.

The assumption concerning nuclear retirements is not quite as critical as that concerning coal-fired plant capacity utilization, but it is still very significant. The Reference Case assumes that 50% of the existing nuclear capacity that reaches the expiration date of the facility's current Nuclear Regulatory Commission (NRC) license is granted a license extension that allows for the continued operation of the unit. To date, however, no nuclear license extensions have been granted. With no

Figure D-11. Influence of Key Assumptions on Natural Gas Demand



precedent to guide it, the Task Group cannot say with any sense of assurance that 50% of licenses will or will not be re-issued. To the extent that future re-licensing differs from the 50% assumption, gas demand for electricity generation could be increased or decreased from the Reference Case.

In the Reference Case, nuclear generation accounts for 15.4% of lower-48 electricity generation in 2010 and 12.4% in 2015. A sensitivity analysis was conducted testing cases in which nuclear generation was 20% above and 20% below the Reference Case level. A 20% change in nuclear generation would add or subtract between 650 and 800 BCF (depending on the plants involved) of gas consumption annually from the Reference Case levels. The range is dependent on the amount of nuclear capacity in service in any particular year.

A note concerning electricity generation sensitivities is required. The results cited above utilize a somewhat different approach from the model because the results present the demand sensitivities in isolation. These scenarios are not "fully integrated" in the same manner as the GDP and oil price sensitivities that follow. Rather, the demand increments presented assume the delivered price of gas remains unchanged from the Reference Case levels. By presenting the analysis in this manner, the magnitude of the effects of electricity generation sensitivities can be fully appreciated and not complicated by large changes in the gas supply or transmission and storage requirements.

Higher GDP Growth Case

The higher GDP growth case assumes an annual growth rate of 3.0% throughout the study period. It further assumes that industrial production grows at an annual growth rate of 3.5% throughout the study period, because productivity improvement is sufficient to support the higher level of economic expansion. Under the higher GDP growth case, U.S. gas demand grows by an additional 0.6 TCF above the Reference Case in 2010, and by 0.9 TCF in 2015.

Lower GDP Growth Case

The lower GDP growth case assumes an annual growth rate of 2.0% throughout the study period. Industrial production grows at an annual rate of 2.5%. Under the lower GDP growth case, U.S. end-use gas demand declines from the Reference Case by 0.9 TCF in 2010 and by 1.1 TCF in 2015.

Higher Oil Price Case ($22/bbl)

The higher oil price case assumes that oil price is $3.50/bbl higher than the $18.50 assumed in the Reference Case. Under the higher oil price case, gas demand grows in 2010 by 0.7 TCF and in 2015 by 2.0 TCF (includes lease plant and pipeline fuel).

Lower Oil Price Case ($15/bbl)

The lower oil price case assumes that oil price is $3.50/bbl lower than the $18.50 assumed in the Reference Case. Under the lower oil price case, gas demand declines in 2010 by 1.0 TCF and in 2015 by 1.9 TCF (includes lease plant and pipeline fuel).

Weather

As indicated in the discussion of Reference Case assumptions, the 1999 Study assumes that weather during the study period will remain normal. Obviously, weather—as it always has—will vary substantially and will have pronounced short-term impacts on demand, price, peak day, and other important variables. However, weather predictions over extended periods of time—such as those involved in the study period—are notoriously unreliable. Assumptions concerning "normal" weather are based on a 30-year average published by the National Oceanic and Atmospheric Administration (NOAA) and revised every 10 years. There is no statistical basis to assume anything other than normal weather over a 15-year study period.

Conclusions Concerning Sensitivities

It is important to understand that the deltas are not cumulative. Before attempting to calculate a different result than the Reference Case, it is necessary to make a certain set of assumptions and then select an end result based on those assumptions. Figure D-11 illustrates the variations resulting from various assumptions.

SUPPLY TASK GROUP REPORT

Table of Contents for Supply Task Group Report

Summary and Key Findings of the Supply Task Group

North America has substantial natural gas resources in place. The NPC estimates remaining lower-48 natural gas resources to be 1,466 trillion cubic feet (TCF)—an increase of 171 TCF, or 13.2%, from the 1,295 TCF estimate contained in the in the NPC's 1992 study on natural gas (hereinafter referred to as "the 1992 Study"). Approximately 124 TCF have been produced in the intervening years, 1992 through 1998. Thus, net of intervening production, the total change in resource assessment is approximately 295 TCF, or 23% greater than the 1992 Study's resource base. This resource base is more than sufficient to supply expected growth in U.S. natural gas demand well into the twenty-first century—but if and only if the following significant challenges are fully addressed through the cooperation of the producing sector, government, and other significant stakeholders:

- Restricted access to resource-bearing public lands limits (both onshore and offshore) the availability of natural gas supply.
- A healthy oil and gas producing sector is crucial for natural gas supply to satisfy expected increases in demand. The producing sector must do the following:
  - To attract required capital, demonstrate and maintain financial performance that is substantially better than historical returns
  - Replenish attrition from an aging workforce
  - Expand the existing drilling rig fleet while replacing older obsolete rigs.
- Continued investment in research and development will be needed to maintain the pace of advancements in technology.

It is industry's challenge to attract the investment capital and human resources necessary to build rigs and service-related assets, maintain the pace of technology advancement, and explore for, develop, and produce ample quantities of natural gas to attain this goal. It is government's challenge to minimize impediments to a competitive marketplace for not only the end-use consumer, but also for companies involved in risky exploration and production of natural gas. This partnership between government and the oil and gas industry is essential to enable the development of sufficient quantities of natural gas supplies to meet the nation's economic and environmental goals.

The producing sector has shown remarkable resiliency during the seven years since the 1992 Study despite extremely difficult and challenging economic conditions. During the next decade, the producing sector will be challenged to grow natural gas production to satisfy unprecedented levels of demand in an increasingly competitive marketplace.

Growth in natural gas demand is expected to be driven largely by increases in gas utilization to generate electricity. Electric power providers are in the process of undergoing dramatic restructuring as a result of state and federal efforts to encourage increased competition in this sector of the energy industry. Such restructuring will intensify the electric power sector's desire for reliable fuel supplies at competitive prices. A fiscally healthy natural gas producing sector is essential to take advantage of the substantial opportunities to enhance the reputation of natural gas as a reliable, environmentally friendly, competitively priced fuel.

Continued funding for research and development (R&D) is crucial, because technology advancements are essential to produce increased quantities of natural gas resources at competitive prices. Cooperative efforts between government and industry are needed to facilitate the investment in R&D required for these technology advancements to occur. The 1999 Study's conclusions are highly dependent on continuous improvement in technology. The ability to produce increased supplies of natural gas from even the current robust resource base will be severely stressed should technological advancements stall or fail to occur.

The natural gas exploration and producing sector also needs reasonable and predictable requirements—uniformly applied—that first, enable the industry to assess the commercial viability of developing natural gas from resource-bearing lands managed by governmental entities. Second, for those prospects determined to be commercially viable and desirable to develop, similar reasonable and predictable requirements are imperative to ensure timely access for exploration, development, and production activities. Most notable among these lands are areas in the Rocky Mountains and the Eastern Gulf of Mexico. Prior cooperative efforts by industry and government—i.e., deepwater royalty relief and Section 29 credits—have been successful and mutually beneficial. The NPC believes that increased access to public lands via predictable, uniformly applied land management policies, drafted from a sense of shared opportunity, can be equally successful and beneficial by enabling development of additional profitable quantities of natural gas with related enhancement in government royalty revenues.

The NPC notes that if natural gas demand were merely to grow at the same rate as the U.S. economy (which is estimated to grow at the modest pace of 2.5% per year), demand for natural gas would increase by 32%—from 22 TCF in 1999 to roughly 29 TCF by 2010—and could increase beyond 31 TCF by 2015. The energy marketplace is intensely competitive, and maintaining natural gas's market share is not guaranteed. Nonetheless, the Council expects growth from strong demand drivers in gas-fired electric power. This growth is a significant challenge to the producing sector, which is only beginning to recover from a difficult business environment which occurred from late 1997 through early 1999. Yet, the NPC firmly believes that all of these challenges can be overcome to the mutual benefit of the economy, the environment, and the nation's energy consumers, as well as companies responsible for natural gas exploration, development, production, marketing, transmission, and distribution.

Key Findings of the Supply Task Group

1. Sufficient resources exist to meet growing demand well into the twenty-first century.

   - With over 1,460 TCF of U.S. and nearly 670 TCF of Canadian remaining resources, supply is available to satisfy a 30+ TCF per year market for many decades.

   - Future U.S. demand will be satisfied from increasingly challenging sources of production, between 1998 and 2015.

     – Deepwater production from the Gulf of Mexico, currently in its infancy, is projected to increase more than five-fold from 0.8 TCF to a projected 4.3 TCF annually.

     – Onshore production from nonconventional formations is projected to increase from 4.4 TCF to 8.5 TCF, with most such production coming from tight, low-permeability reservoirs.

     – Onshore production from deep conventional formations (>10,000 feet) is projected to increase by approximately 20% from 4.6 TCF to 5.5 TCF.

   - Imports from Canada are projected to continue to be important in meeting U.S. demand. The 1999 Study is projecting that Canadian supply will continue to account for 13–14% of projected total lower-48 supply.

   - Of nearly equal importance, lower-48 gas associated with oil production must be sustained. Associated gas will continue to account for approximately 15% of lower-48 supply.

2. Restricted access limits the availability of natural gas supply.

   - To increase the production of natural gas, access to resources is critical for areas onshore and offshore as well as new regions.

   - Currently, access is limited in the Rockies, Eastern Gulf of Mexico, and off both the Atlantic and Pacific U.S. Coasts.

   - Efforts must be funded to update land management plans for natural gas resource-bearing federal acreage, and administration of access regulations among governmental agencies must be consistent to ensure that exploration, drilling, and production activities proceed.

   - Access to frontier areas will be required for long-term sustainability.

3. A healthy oil and gas industry is critical for natural gas supply to satisfy expected increases in demand.

    - Over $650 billion (1998$) of capital expenditures will be required in the United States through 2015 to fund exploration, drilling, and production of sufficient supplies needed to satisfy projected growth in U.S. demand.

    - Financial performance substantially better than historical returns must be demonstrated to compete for and attract investment capital to the U.S. and Canadian upstream sectors.

    - Aging rig fleets and service assets will require replacement and expansion.

    - An aging workforce necessitates immediate aggressive action by the producing sector to attract, train, and retain qualified workers at all levels.

    - Industry must also aggressively undertake initiatives to attract high school students with strong math/science skills to replenish diminished university enrollments in Petroleum and Geoscience disciplines and attract similarly capable personnel to skilled trades associated with the upstream sector.

    - As a growth industry, upstream companies and their investors must avoid excessive reactions to short-term performance that conflict with long-term strategic growth expectations.

    - The actual or perceived benefit of environmental legislation or regulation must be carefully balanced against the potential to impose higher costs on natural gas exploration and production, significantly limiting the efforts of industry to supply increasing natural gas demand at competitive prices.

4. Investment in research and development will be necessary to maintain the pace of technological advancement.

    - The 1999 Study foresees a shift in focus from "better tools" to "better techniques." Technology is expected to focus on data interpretation and integration.

    - A more collaborative approach among industry, government, and academia for developing upstream technology must continue and expand.

    - Technological advancement will significantly impact the ability to explore for, produce, and develop increasingly deeper, more remote, and nonconventional deposits of natural gas.

Overview of Methodology for Supply Analyses

The Supply Task Group was responsible for (1) reviewing the resource base, technology, and cost assumptions made in the 1992 Study, (2) recommending changes for the analyses to be made in the 1999 Study, (3) reviewing various model projection cases and other study results, and (4) writing this report. The Supply Task Group organized itself into eight regional resource assessment subgroups. Additionally, three supporting subgroups investigated upstream technologies, reserve appreciation in existing fields, and upstream financial/policy matters.

The Supply Task Group met several times over the 12-month study period, and each of the subgroups met as required. In addition to these deliberations, two special studies were conducted to look into the reserve appreciation potential of existing U.S. fields and the amount of natural gas resources in the Rocky Mountain area restricted by various federal land management laws and practices. Also, two limited surveys were conducted by the Supply Task Group to assess recent R&D funding trends in the oil and gas production industry and its support industries and the demographics of the workforce at large oil and gas producing companies.

The intent of the Supply Task Group was not to conduct a comprehensive review of the U.S. and Canadian natural gas resource base and other forecasting assumptions. Rather, its objective was to identify those areas where industry experience over the last seven years and current expectations differed significantly from the conclusions reached in the 1992 Study. Those changes were incorporated into the GRI Hydrocarbon Supply Model (HSM) as a basis for an updated natural gas supply projection. As in the 1992 Study, areas in which there were significant uncertainties about the future—most notably the size of the remaining resource base, restrictions on land access, and the pace of technological advances—were the subject of supply sensitivity analyses.

Modeling Framework

The HSM was developed and refined for the Gas Research Institute (GRI) under a contract that began in the early 1980s with Energy and Environmental Analysis, Inc. (EEA). The HSM was used to investigate gas supply issues for the NPC's 1992 Study on natural gas. The HSM is a PC-based analytical framework designed for the simulation, forecasting, and analysis of natural gas, crude oil, and natural gas liquids supply and cost trends in the United States and Canada. The HSM, along with the gas transmission and demand components of EEA's Gas Market Data and Forecasting System were chosen as the modeling systems for the 1999 Study. The repeat use of the HSM for the 1999 Study allowed the Supply Task Group to start its analysis using the same assumptions contained in the 1992 Study. Starting with these assumptions, a series of successive cases were developed in which various new assumptions were tested and adopted until the final "Reference Case" was decided upon.

Update of Regional Resource Assessments

To help decide where changes needed to be made, the regional resource assessment subgroups first identified where the projections from the 1992 Study deviated from what actually happened. (See Appendix E for additional information on the retrospective look at the 1992 Study.) The subgroups also looked at the underlying resource base assumptions and the post-1999 projections from the model to further determine where current expectations differed significantly from the conclusions reached in the 1992 Study. To help the regional assessment subgroups in their deliberations, EEA gave each group a package containing the following information:

- The resource base assumptions from the 1992 Study
- The gas drilling activity, reserves, and gas production projected in the 1992 Study through the end of 1997, by type of gas (non-associated, associated-dissolved, coalbed methane, shales, and tight gas) and actual history for the same items
- Historical exploration activity and discovery trends by field size and drilling depth (generally from the 1940s through the mid-1990s)
- Where available, historical statistics on nonconventional gas drilling activity, production, and ultimate recovery per well
- Reserve appreciation to existing fields for recent years from Energy Information Administration (EIA) Form 23 data
- Alternative resource base assumptions from several other sources including the U.S. Geological Survey, the U.S. Potential Gas Committee, GRI, Canadian Geological Survey, the National Energy Board of Canada, and Canadian Gas Potential Committee.

Using this information, additional data provided by the Supply Task Group members, and their own experience and knowledge about the areas in question, the regional resource assessment subgroups recommended changes to various modeling assumptions. The major areas of change were increases in the new field assessment in the deepwater Gulf of Mexico and in the Eastern Gulf of Mexico, and various adjustments to the coalbed methane and shale resources in several basins. These changes were incorporated into the HSM for the successive model runs, each including new data and assumptions created and refined as the study proceeded. In some instances, results of these projections were presented and discussed at Peer Review Sessions with industry personnel who were not direct participants of the NPC study.

The resource base assumptions that resulted from this process are described in Chapter One of this Supply Task Group Report. Alternative assumptions used in the Larger Resource Base and Smaller Resource Base sensitivities are presented in Chapter Five.

Reserve Appreciation Studies

Two statistical analyses were conducted to update the assumptions used in the 1992 Study for the potential for reserve appreciation from existing fields. The first approach was an update to EEA's analysis conducted for GRI in 1993 based on the observation that successive increments of drilling in fields of a certain age show declining reserves added per well. By extrapolating those declining recoveries, it is possible to estimate how many economic reserves could be added by additional gas completions in existing fields. The 1999 Study was conducted by EEA using publicly available data from PI/Dwights gas well reports.

The second approach was to match annual Estimated Ultimate Recovery (EUR) derived from confidential EIA Form 23 data with gas well drilling activity from the PI/Dwights gas well reports. Those data were then used to estimate growth curves for each field vintage (i.e., all fields found in one year) within a region as a function of time and the number of wells drilled in those fields. The Dallas Field Office of EIA, using confidential information contained in the Form 23 reserve reports, performed this work.

The two statistical approaches yielded very similar results that led to an increase in the old field appreciation resource relative to the 1992 Study. The Reference Case assumptions for field growth are shown in Chapter One of this Supply Task Group Report. The data and methodology are more fully discussed in Chapter Seven and in Appendix K.

Rocky Mountain Land Access Study

The financial/policy subgroup of the Supply Task Group conducted a special study of federal land restrictions on oil and gas development in the Rocky Mountain region. This was the first comprehensive attempt to determine how federal laws and policies are restricting access to natural gas resources. The 1999 Study was conducted with the cooperation of several federal and state agencies and involved the creation and processing of significant amounts of Geographical Information System (GIS) data.

The impact of "current policy" as determined in the 1999 Study was incorporated into the Reference Case. Two alternative cases for Rocky Mountain land access were also modeled, one with more restricted access and a second reflecting the impact of more efficient and balanced federal land management practices. These assumptions for the Rockies were combined with like assumptions for offshore areas into "Increased Access" and "Reduced Access" cases.

A discussion of the access case results can be found in Chapter Two of this Supply Task Group Report. Background material on the access issue and details of the Rocky Mountain access GIS study can be found in Appendix J.

Surveys

The Supply Task Group conducted two surveys during the 1999 Study. The first was an informal survey by the technology subgroup of oil and gas producers and support companies concerning trends in R&D spending and practices. The purpose of the survey was not to estimate expenditure levels *per se*, but to learn how the companies were coping with lower R&D spending. The results of this inquiry are presented in Chapter Four of this Supply Task Group Report, with additional details provided in Appendix L.

The second survey augmented information from four major oil and gas producers regarding the age distribution of their workforce. This information was used in the discussion of workforce requirements that appears in Chapter Three of this Supply Task Group Report.

Chapter One

Sufficient Resources Exist to Meet Growing Demand Well into the Twenty-First Century

Overview of North American Natural Gas Resource Base

North America contains abundant resources of natural gas, and a large portion of this resource base has yet to be discovered. Table S-1 summarizes the current NPC assessment of the North American gas resource base, and compares the assessment to that of the 1992 Study. Shown on the table are assessment data for the lower-48 states, Alaska, and Canada. (Alaska resources were not assessed in the 1999 Study, and the values shown in the table are from published sources.) Total All-Time Recovery for the three areas totals over 3,400 TCF, and Total Remaining Resources are over 2,400 TCF. A glossary of natural gas resource base terminology is located at the end of this chapter.

Lower-48 Total Remaining Resources of 1,466 TCF in the 1999 Study represent a 13.2% (171 TCF) increase from the 1,295 TCF of the 1992 Study. Canada's Total Remaining Resources are assessed to be 667 TCF. The work of the Supply Task Group on resource assessment indicates a high level of confidence in the robustness of the North American resource base.

The Supply Task Group notes that the 171 TCF increase in lower-48 Total Remaining Resources has occurred at the end of a six-year period, 1992 through 1997, in which 124 TCF of reserves were produced in the lower-48 states. During that same period, the Proved Reserves component of Total Remaining Resources declined by a statistically insignificant 3 TCF, from 160 TCF in the 1992 Study to 157 TCF in the 1999 Study. The primary factors contributing to the increase in lower-48 Total Remaining Resources over the period from 1992 through 1998 are:

- **The impact of improved technology.** Technologies such as 3D seismic, directional drilling, and advanced completion methods have had a major impact on activity over the past decade.
- **The increase in resource estimates from Old Field Reserve Appreciation.** The assessment of remaining potential in existing lower-48 oil and gas fields increased from 236 TCF in the 1992 Study to 305 TCF in the 1999 Study. This increase reflects industry's improved ability to identify and exploit opportunities in older fields.
- **Increases in the assessment of resources from New Fields, primarily in the deepwater Gulf of Mexico.** The New Fields resource of 57 TCF estimated for the deepwater Gulf of Mexico in the 1992 Study was increased to 140 TCF for the 1999 Study—an increase of 145%.

As summarized in Table S-2, 89% of the lower-48 Total Remaining Resources remains unproved. In addition, the regions shown on this table contain a combined 68% of the

TABLE S-1

U.S. AND CANADIAN NATURAL GAS RESOURCES
(Trillion Cubic Feet)

	1992 NPC Study* (1-1-91)	1999 NPC Study (1-1-98)
LOWER-48 RESOURCES		
Proved Reserves	160	157
Assessed Additional Resources	1,135	1,309
Old Fields (Reserve Appreciation)	*236*	*305*
New Fields	*493*	*633*
Nonconventional	*406*	*371*
Total Remaining Resources (Proved + Assessed Additional)	**1,295**	**1,466**
Cumulative Production	758	881
Total All-Time Recovery	2,053	2,347
ALASKAN RESOURCES†		
Proved Reserves	9	10
Assessed Additional Resources	171	303
Old Fields (Reserve Appreciation)	*30*	*32*
New Fields	*84*	*214*
Nonconventional	*57*	*57*
Total Remaining Resources (Proved + Assessed Additional)	**180**	**313**
Cumulative Production	5	9
Total All-Time Recovery	185	322
CANADIAN RESOURCES		
Proved Reserves	72	64
Assessed Additional Resources	668	603
Old Fields (Reserve Appreciation)	*24*	*22*
Discovered Undeveloped	*47*	*35*
New Fields	*379*	*384*
Nonconventional	*218*	*162*
Total Remaining Resources (Proved + Assessed Additional)	**740**	**667**
Cumulative Production	65	103
Total All-Time Recovery	805	770

*Assessed Additional Resources from the 1992 Study reflect re-allocation of tight gas resources among categories consistent with 1999 Study allocations.

†Old Fields resource includes 25 TCF for Prudhoe Bay; New Fields resource is based on 1995 USGS/MMS assessment; and Nonconventional resource is PGC coalbed methane resource.

TABLE S-2

LOWER-48 NATURAL GAS RESOURCE BASE ANALYSIS OF KEY PRODUCING REGIONS

Resource Area	Proved Reserves (TCF)	Assessed Additional Resources (TCF)	Total Remaining Resources (TCF)	Assessed Additional Resources as a % of Remaining
Rockies*	36	346	382	91%
Gulf of Mexico	33	319	352	91%
Texas Gulf Onshore	15	116	131	89%
Mid-Continent	26	112	138	81%
All Other Areas	47	416	463	90%
Total	**157**	**1,309**	**1,466**	**89%**
Cumulative through 12/97			881	
Total All-Time Recovery			2,347	

*Rockies = Foreland + Overthrust + San Juan + Williston model regions.

potential Assessed Additional Resources in the lower-48 states. This information is further illustrated for all of North America in Figures S-1a and S-1b. Because of the importance of the four regions shown in Table S-2 and the Western Canadian Sedimentary Basin to future North American gas supply, the Supply Task Group concentrated its effort on the assessment of these regions.

Reference Case Results

U.S. natural gas supply is projected in the Reference Case to grow as shown in Table S-3. As is shown in the table, Canada will continue to be a significant supply source, providing about 14% of U.S. gas supply throughout the projection.

Future lower-48 production is expected to be from deeper and more nonconventional sources. Table S-4 shows projected gas production by reservoir type. While associated-dissolved gas production is projected to maintain its share of about 14%, the relative contribution of high permeability non-associated gas production will decline. Nonconventional production, especially from tight gas reservoirs and coalbed methane, will increase substantially. A significant factor supporting the continued production of associated gas is the emergence of the deepwater play in the Gulf of Mexico, which is predominantly associated gas.

Growth in production from nonconventional sources will be especially pronounced in the Rocky Mountain Foreland region. In 1995, nonconventional production (i.e., the sum of tight gas and coalbed methane) in that region was 0.5 TCF, accounting for 45% of total production. This is projected to increase to over 2.0 TCF, or 76% of total production by 2010, as detailed in Table S-5. In order to achieve the projected amounts of gas production from coalbed methane and tight gas, technological hurdles will have to be overcome.

As Table S-6 demonstrates, lower-48 onshore production from deeper wells will increase. Most lower-48 gas production is already derived from strata deeper than 5,000 feet (72% as of 1998). Deep drilling is increasing, and 1994 marked the first year in which more than 50% of all wells were drilled to depths deeper than 5,000 feet. Production from depths deeper than 10,000 feet is

Figure S-1a. U.S. and Canadian Assessment Regions

Figure S-1b. Assessed Additional Resources by Region

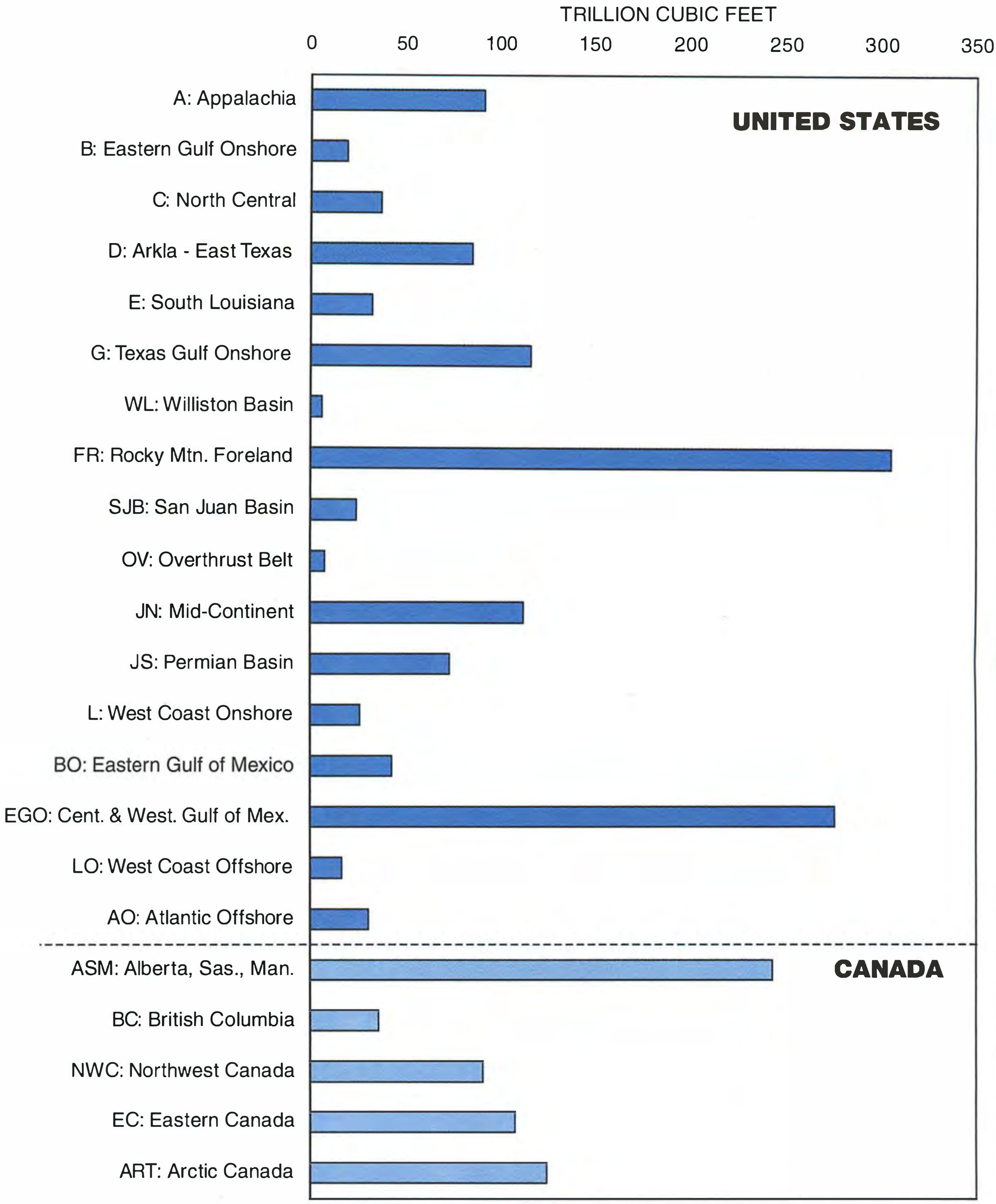


TABLE S-3

U.S. GAS SUPPLY
(Trillion Cubic Feet)

	1998*	2005	2010	2015
U.S. Gas Production	19.0	22.6	25.1	26.6
Net Imports from Canada	3.0	3.7	3.8	4.3
LNG Imports	0.1	0.4	0.6	0.9
Exports to Mexico and Japan	-0.1	-0.4	-0.5	-0.5
Total Supply	**22.0**	**26.3**	**29.0**	**31.3**
Canada as a % of Total	14%	14%	13%	13%

*Including synthetic natural gas.

Source: 1998 actuals from Energy Information Administration, *Natural Gas Monthly*, September 1999.

TABLE S-4

PROJECTED GAS PRODUCTION BY RESERVOIR TYPE
(Production Percentages)

	1995	1998	2000	2005	2010	2015
Associated	14%	14%	13%	13%	14%	13%
High Perm Non-Assoc.	62%	60%	63%	62%	59%	54%
Tight & Shale Gas	17%	20%	19%	20%	21%	25%
Coalbed Methane	5%	6%	5%	5%	6%	8%

TABLE S-5

PRODUCTION FROM NONCONVENTIONAL SOURCES
IN ROCKY MOUNTAIN FORELAND REGION

1995	2000	2005	2010	2015
45%	57%	72%	76%	79%

TABLE S-6

ONSHORE LOWER-48 GAS PRODUCTION BY DEPTH

	1998	2000	2005	2010	2015
0-5,000 ft	28%	28%	27%	25%	25%
5-10,000 ft	39%	37%	37%	34%	32%
10-15,000 ft	26%	27%	26%	29%	32%
>15,000 ft	7%	8%	10%	12%	11%

expected to increase from 35% in 2000 to 41% by 2010. It is important to note, however, that industry's ability to achieve production from deeper horizons will be dependent on adequate deep drilling infrastructure and the continued evolution of technology.

Production from deeper waters of the Gulf of Mexico will be a driving force in future supply growth. Table S-7 shows the projected importance of gas production from water depth intervals of 200 meters (656 feet) or more. Deepwater production is increasing rapidly and is projected to represent a very important component of North American gas production by 2015. In Chapter Four of this Supply Task Group Report, some of the innovations needed to achieve the projected deepwater production are discussed in detail.

TABLE S-7

GULF OF MEXICO PRODUCTION

	1995	1998	2000	2005	2010	2015
Production (TCF/Year)	5.2	5.3	5.7	7.4	8.0	7.6
Conventional Production (%)						
Shelf 0-40 meters	53%	49%	40%	27%	20%	19%
Shelf 40-200 meters	39%	35%	31%	24%	20%	17%
Slope 200-1,000 meters	8%	14%	19%	26%	25%	23%
Slope 1,000-1,500 meters	0%	0%	4%	9%	13%	14%
Slope >1,500 meters	0%	1%	2%	8%	15%	18%
Subsalt Production (%)						
Shelf 40-200 meters	0%	< 1%	3%	3%	4%	4%
Slope 200-1,000 meters	0%	1%	1%	2%	2%	3%
Slope >1,000 meters	0%	0%	0%	1%	1%	2%

Glossary of Resource Base Terminology

- *Proved Reserves:* the most certain of the resource base categories representing estimated quantities that 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; generally, these gas deposits have been "booked," or accounted for as assets on the SEC financial statements of their respective companies

- *Assessed Additional Resources:* the sum of natural gas deposits estimated to be in-place (using accepted engineering models and analytical tools) that will become recoverable in the future at various assumed technology and price levels; current economic and operating conditions are insufficient to justify Proved Reserves status for this category, which includes the following:

  - *Old Field Reserve Appreciation:* additional estimated conventional and nonconventional resources resulting from the recognition that currently booked Proved Reserves are conservative by definition and will continue to grow over time; based on historical experience, existing fields have been shown over time to contain, and ultimately produce, significant additional quantities of natural gas in excess of initial proved reserve estimates

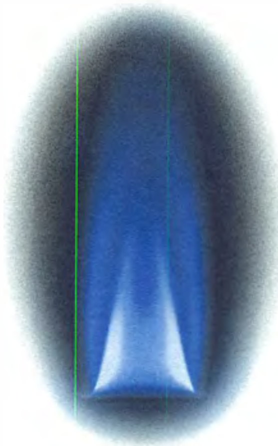
  - *New Fields:* a quantification of resources estimated to exist outside of known fields on the basis of broad geologic knowledge and theory; in practical terms, these are statistically determined resources likely to be discovered in additional geographic areas with geologic characteristics similar to known producing regions, but which are as yet untested with the drillbit

  - *Nonconventional:* resources that are estimated to be contained in known strata of deposits requiring application of technologies different from those required to extract high permeability gas reserves (e.g., shale gas, coalbed methane, tight gas, etc.)

- *Total Remaining Resources:* the sum of Proved Reserves and Assessed Additional Resources; this term is often used interchangeably with "Total Resources" and refers to the total quantity of natural gas estimated to remain available for production

- *Cumulative Production:* the total volume of natural gas that has been withdrawn from producing reservoirs

- *Total All-Time Recovery:* the sum of Total Remaining Resources plus Cumulative Production; the estimate of total natural gas that will ultimately be produced after all wells cease economic production



Chapter Two

Restricted Access Limits the Availability of Natural Gas Supply

Lack of, or excessive interference with, access to U.S. natural gas resources will impair development in several key areas, and will impede the construction of needed pipelines required to deliver natural gas to markets. For the purposes of the 1999 Study, the following assumptions were made with regard to access:

- All scheduled lease sales will continue on time (including proposed Minerals Management Service (MMS) Lease Sale 181 in the Eastern Gulf of Mexico).
- All existing regulatory requirements and restrictions on (as well as any and all current rights to drill on) public lands are honored.
- Rights-of-way will be obtained for constructing and expanding any necessary pipeline infrastructure.

If any of these assumptions fall short, the ability to explore for, produce, and deliver adequate natural gas supplies will be impaired.

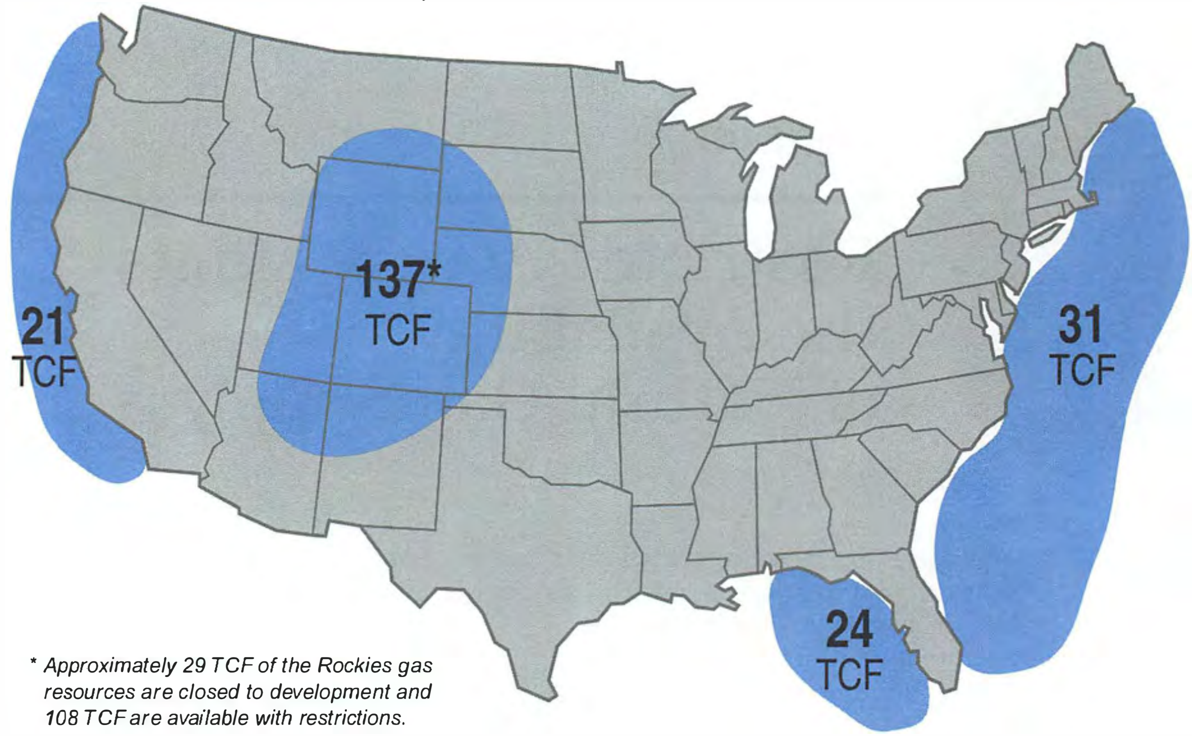
Two areas that will significantly contribute to future U.S. gas supplies are the Rocky Mountain Region and the Gulf of Mexico, both of which have significant access restrictions. In the Rocky Mountains, remaining natural gas resources have been estimated in the 1999 Study to be roughly 380 TCF, of which over 75%, or about 290 TCF, underlie federal land—in other words, 20% (one-fifth) of the 1,466 TCF of lower-48 remaining resource is located on Rocky Mountain federal lands.

Appendix J, Part 1, describes the methodology used in the 1999 Study to assess Rocky Mountain access issues. This assessment resulted in the following determinations regarding percentage availability of undeveloped gas resources on federal lands for natural gas exploration and production activity:

- 9% of gas resources on lands that are completely inaccessible due to "no leasing" and "no surface occupancy" restrictions (hereinafter referred to as "No Access" lands)
- 32% of gas resources on lands that are specifically subject to restrictions that delay development activity by an average of two years and cause a risk-weighted increase of roughly $25,000 in the cost of drilling each well on these properties (hereinafter referred to as "High Cost" lands)
- 59% of gas resources are on lands that are subject to "standard leasing terms" that are developed as economic conditions warrant.

As a practical matter, regardless of the lack of specific stipulations, "standard leasing terms" have regularly been interpreted very restrictively, resulting in delays and added costs on Rocky Mountain public lands that are otherwise accessible for development. Such

Figure S-2. Lower-48 Natural Gas Resources Subject to Access Restrictions



lands regularly become encumbered in disputes among stakeholder groups and inconsistent application of regulatory policy by the governmental group(s) charged with managing these lands. However, for purposes of the 1999 Study Reference Case, the Supply Task Group chose to allow access without cost penalties or delays to that 59% of Rockies public acreage subject to "standard leasing terms." This assumes that legislation, regulation, and administrative policies provide more expeditious means for resolving disputes and inconsistencies so that development may proceed.

Offshore resources in much of the Eastern Gulf of Mexico are also off-limits to development. In the Eastern Gulf, remaining natural gas resources have been estimated in the 1999 Study to be nearly 50 TCF, much of which is physically proximate to substantial infrastructure from development that has occurred in eastern segments of the Central Gulf of Mexico. Mobile Bay is the only area in the Eastern Gulf that has been developed. Mobile Bay accounts for roughly 16 TCF (one-third) of the Eastern Gulf of Mexico resource base; thus, at the present time, nearly 34 TCF of Eastern Gulf resource is undeveloped. The 1999 Study assumes that proposed MMS Lease Sale 181 will occur as scheduled in December 2001, and production from this area will commence in 2004. Should Lease Sale 181 occur as planned, development of an additional 9 TCF of resources will commence. Stated another way, after Lease Sale 181, half of the Eastern Gulf resources will remain off-limits during the study period. The 1999 Study Reference Case does not assume that access will be granted during the study period for development of the 24 TCF off the Florida coast, as illustrated above (except for tracts in the Lease Sale 181 area); these areas have not been opened up and no plans to do so are presently in progress. Similarly, the Destin Dome area off the panhandle of Florida is not assumed to commence production in the Reference Case; approval processes are incomplete and remain in a state of significant uncertainty in this promising area just east of existing production in Mobile Bay.

Figure S-2 provides an overview of the lower-48 natural gas resources that are subject to access restrictions. Of the almost 215 TCF of Total Remaining Resources under restriction, about half are not open to either assessment or development and the remainder are subject to significant restrictions.

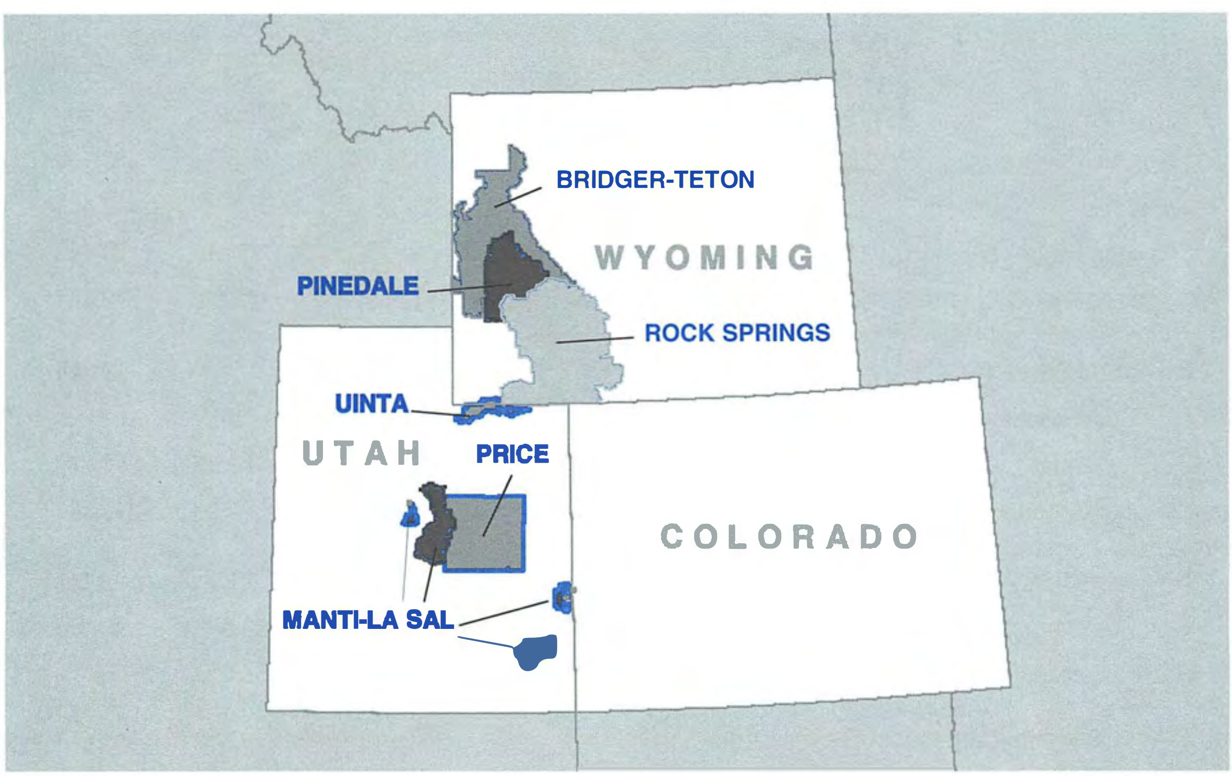
Discussion of Rocky Mountain Access Issues

According to a 1997 report by the Cooperating Associations Forum, entitled *Federal Land Access to Oil and Gas Minerals in Eight Western States*, discretionary restrictions apply to an average of 57% of Bureau of Land Management (BLM) and Forest Service lands in the eight states reviewed (California, Colorado, Montana, Nevada, New Mexico, North Dakota, Utah, and Wyoming). Assumptions used in the 1999 Study optimistically imply a bit more openness in application of those discretionary restrictions as the nation's growing need for cleaner-burning natural gas is balanced against other concerns associated with multi-use federal land; however, this increased openness is by no means assured.

For the 1999 Study, several individuals from the BLM and Forest Service combined with industry representatives to form a team that was instrumental in assessing the status of access issues in the Rocky Mountain region. Early on, all participants recognized the need for a comprehensive and consistent digitized inventory of acreage by land use that could be made available to all federal lands management agencies and other interested parties. Lacking such an inventory and database, assessing the impact of access restrictions on Rocky Mountain resource availability in the 1999 Study occurred by extrapolating results from a detailed study of sample key resource-bearing areas within the region. Figure S-3 shows the names and locations of those areas.

Furthermore, part of the problem in assessing access questions is that "official policy" and "practice" often diverge. (See Appendix J, Part 2.) Application of restrictions is inconsistent both inter- and intra-agency. Industry stands able to apply its considerable expertise toward exploration and production of resources in the Rocky Mountain region using environmentally conscious drilling and development techniques. However, vague laws regarding resource development policy,

Figure S-3. Access Study Areas



even more vague regulations, and a resultant variety of personal interpretations and biases plus third-party stakeholder action has resulted in an excessively difficult environment for natural gas producers in the Rocky Mountains.

Nonetheless, in the 1999 Study, improvement of these conditions was assumed to occur in expectation that all stakeholders would recognize the need for more reasonable rules on access to balance important needs for ample quantities of natural gas to attain environmental goals with other land-use concerns. As a result, the 1999 Reference Case assumed that access restrictions in the Rocky Mountain region would improve, in aggregate, as referred to in the following percentage availability of undeveloped gas resources on federal lands for natural gas exploration and production activity:

- 9% "No Access" lands
- 32% "High Cost" lands
- 59% "standard leasing terms."

Table S-8 shows the NPC's assumptions on how the foregoing restrictions affect available Rocky Mountain resources. These assumptions were based on the actual legal characterizations associated with lands containing natural gas resources in the Rocky Mountains. As stated above, roughly 59% of these resource-bearing lands are subject to so-called "standard leasing terms," which means that they are, at least nominally, accessible for exploration and production activity. Similarly, such characterization also suggests that these lands are available consistent with a producer's normal decision-making process for such activity; i.e., when the economics of a project justify drilling activity, that activity will occur in the due course of business without unusual delays or costs.

The 1999 study participants acknowledge that access to these resource-bearing lands is much more restrictive than the nominal characterization suggests. These resource-bearing lands are managed by BLM/Forest Service

TABLE S-8

IMPACT OF ACCESS RESTRICTIONS ON ROCKY MOUNTAIN REGION
NPC REFERENCE CASE
(Billion Cubic Feet)

	Old Field Reserve Appreciation	New Fields	Coalbed Methane	Tight Gas	Other	Total
Foreland Province	28,949	99,180	29,371	136,972	14,689	**309,161**
Overthrust	702	6,731	0	0	0	**7,433**
San Juan Basin	11,673	2,209	10,058	0	0	**23,940**
Total	41,324	108,120	39,429	136,972	14,689	**340,534**
No Access Resource	0	10,812	2,721	13,971	1,763	**29,266**
High Cost Resource	16,530	37,842	8,793	40,133	4,700	**107,998**
SLT Resource*	24,794	59,466	27,916	82,868	8,226	**203,270**
Total Resource						**340,534**
No Access Percentage	0.0%	10.0%	6.9%	10.2%	12.0%	**8.6%**
High Cost Percentage	40.0%	35.0%	22.3%	29.3%	32.0%	**31.7%**
SLT Percentage*	60.0%	55.0%	70.8%	60.5%	56.0%	**59.7%**

*SLT = "standard leasing terms"

Rocky Mountain Access Study Summary

Analysis of access constraints in the Rockies included review of both actual prohibitions (i.e., lands on which no leasing or no surface occupancy is allowed) and de facto prohibitions (i.e., lands for which access is so drastically time limited as to effectively put the land off-limits to time-consuming gas drilling and development). As time progresses, increasing quantities of natural gas resource will be obtained from wells tapping deeper horizons; these wells take much longer to drill and will intensify the problem posed by the de facto prohibitions. Therefore, the analysis categorized the availability of the resource base underlying Rockies lands as follows:

- Drilling Prohibited <3 months per year: Full Resource Availability
- Drilling Prohibited >9 months per year: No Resource Availability
- Drilling Prohibited >3 but <9 months: the "gray area" – Resource Available, but with cost penalties and delayed development schedules

"Prohibitions," which limit access to resource-bearing lands, are defined to include the combined effect of not only direct lease stipulations, but also other terms and conditions, such as:

- Conditions of Approval imposed in the certification of an Application to Drill – these conditions often arise from Environmental Impact Statements (EIS).
- Delays incurred to obtain a "clean" EIS – industry, not the agency charged with these studies, must often incur costs to conduct an EIS to complete this requirement within a commercially viable period of time. Even then, the time required to analyze, assess, and obtain a "clean" EIS for one development in the Pinedale area took nearly two years to complete. This EIS, originally budgeted at $0.75 million for a 2,800-well program, ultimately cost $2.0 million for a greatly reduced 400-well program.
- Budget restrictions on the governing agency – resource management plans or Habitat Studies at many agency offices are out of date, requiring industry to fund updates in order to further progress toward approval of drilling permits.
- Wilderness Study and Re-inventory Areas – unexpected reclassification placing otherwise available resources under no surface occupancy or other excessive restrictions.
- Habitat Improvement – requirements that prospective drillers plant additional vegetation to remedy problems caused by other resource exploiters (i.e., overgrazing).

The net result of these direct lease stipulations and other terms and conditions on access to Rocky Mountain resources currently adds an estimated $25,000 to the average cost of drilling and delays the drilling activity for an average of two years. As the next decade progresses, these restrictions will cause additional quantities of "gray area" resources to be effectively off-limits. This is because deeper wells will be difficult to drill within the "gray area's" six-month window of opportunity.

area offices. These offices are often also responsible for much larger contiguous acreage for which land management practices are much more restrictive. As a result, land management practices associated with the resource-bearing land segment are often interpreted substantially more restrictivly than nominal legal labels would indicate. If Reference Case Rocky Mountain productive potential is to be realized, more restrictive actual practices will have to be replaced with accessibility more consistent with nominal characterizations of resource-bearing lands.

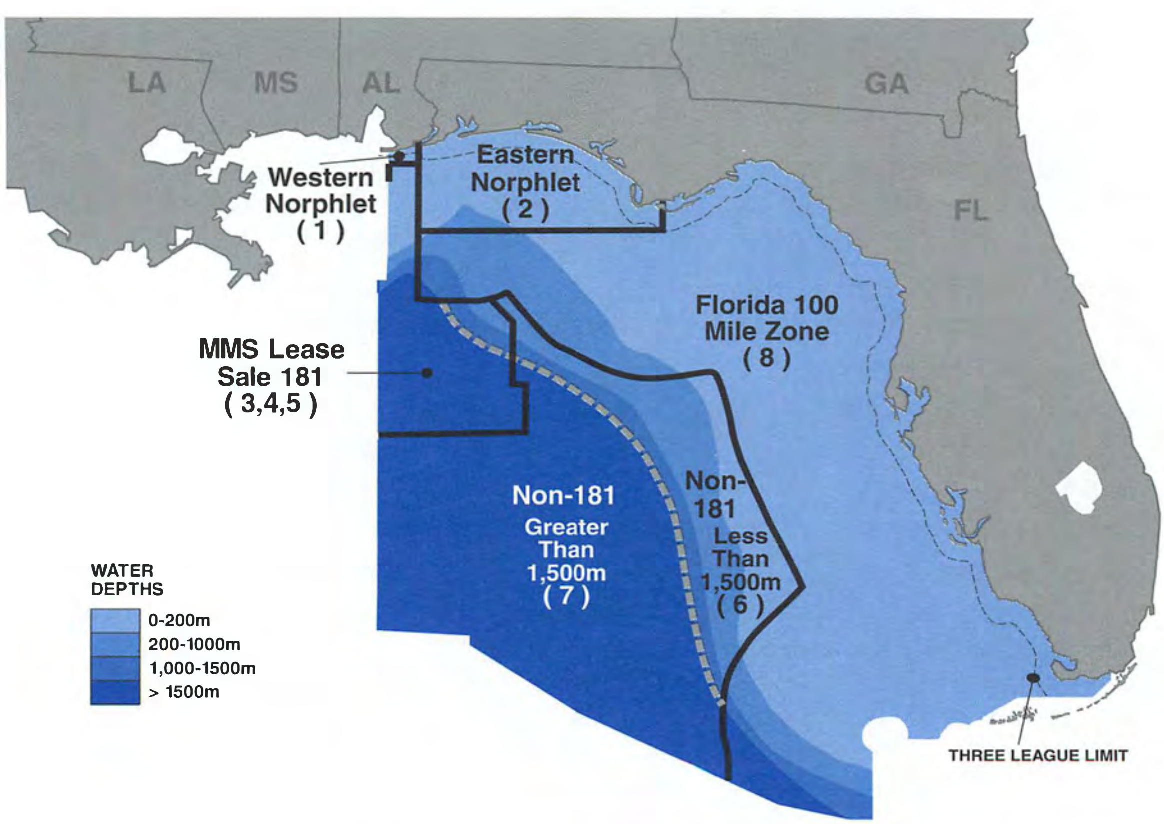
Discussion of Eastern Gulf of Mexico Access Issues

The model used to test assumptions for the 1999 Study divides the Eastern Gulf of Mexico in to eight Subregions. Figure S-4 shows those regions. At the present time, only Subregion 1, entitled Western Norphlet (i.e., Mobile Bay), is producing natural gas. Subregion 2, entitled Eastern Norphlet (i.e., Destin Dome) has been under review by several operators for many years; however, complicated federal and state concerns for exploration and producing activity have repeatedly delayed development of prospects identified in this area, which is immediately adjacent to substantial production in Mobile Bay. For purposes of the 1999 Study Reference Case, Subregion 2 is not assumed to be developed during the study period. Subregions 3, 4, and 5 comprise the area that will be made available for development in proposed MMS Lease Sale 181 scheduled to occur in December 2001. The 1999 Study Reference Case assumes that MMS Lease Sale 181 proceeds as planned and with first production of marketable quantities of natural gas by around 2007. For the Reference Case, Subregions 6, 7, and 8 are not assumed to be developed nor produce natural gas during the study period.

Access Issues for Other Offshore Regions

By Executive Order dated June 12, 1998, President Clinton extended the moratorium

Figure S-4. Eastern Gulf of Mexico Subregions



on development of offshore U.S. Atlantic and Pacific natural gas reserves through the year 2012. The moratorium had been scheduled to expire in 2002. The natural gas resource base associated with these areas totals 21 TCF in the Pacific and 31 TCF in the Atlantic. At today's natural gas prices, a substantial quantity of this resource base is accessible through safe and environmentally conscious drilling techniques perfected in the Gulf of Mexico.

Additionally, the Eastern Gulf of Mexico contains 24 TCF that are inaccessible due to state and federal moratoria. As shown in Figure S-4, a substantial percentage of these off-limits resources are in readily accessible areas where natural gas production facilities would be well beyond the view from the Florida Gulf Coast.

Access-Related Public Policy Issues

A clearly delineated public policy supporting development of ample supplies of natural gas is critical in order to satisfy growing demand at reasonable prices. Excessive restrictions on development of otherwise easily accessible and readily marketable domestic supplies of natural gas will impair the ability of natural gas to successfully contend for market share among increasingly price-sensitive electric power and industrial customers. Removing impediments to opportunities for growth in natural gas market share among these customers is necessary to support national economic and environmental goals.

Clarification of public policy regarding the role of natural gas in attaining environmental objectives will be crucial. Such public policy should encourage market forces to suggest wise environmental choices. Critical path market forces must include attaining air-quality environmental objectives without the economic detriment of higher energy commodity prices. For market forces to ensure reasonable natural gas commodity prices, policy must enable development of ample supplies of natural gas. Definitive governmental goals and objectives for clean-burning natural gas are especially needed in three key areas: (1) development of offshore U.S. resources currently encumbered by moratoria, (2) development of onshore public lands resources currently encumbered by access restrictions, and (3) reversal of the trend toward increased environmental costs associated with drilling and development.

Over 105 TCF of Total Remaining Resources have been effectively placed off-limits to development—offshore moratoria account for 76 TCF, with 29 TCF located in national parks, monuments, and other sensitive areas. Additionally, another 108 TCF in the Rocky Mountains are subject to substantial restrictions. Excluding national parks, monuments, and other sensitive areas, the 184 TCF subject to moratoria and other restrictions represents nearly 13% of lower-48 Total Remaining Resources.

Relief from these restrictions is needed in order for the Rocky Mountain's vast resource base to realize its full potential in supplying increased demand for natural gas at reasonable prices. Likewise, industry will have to be much more diligent in executing development plans in order to achieve strategic goals under such constraints.

- Relief from restrictions can come in the form of additional funding to key agency offices that manage lands bearing the most promising quantity of resource base. This would enable these offices to maintain current status for all resource management plans, Habitat Studies, and other responsibilities, which would enable industry to expedite drilling and development.
- Relief from restrictions may also come in the form of creating a uniform land-management plan that eliminates inconsistency in statutory and regulatory interpretation within and among federal agencies and better coordinates with state agencies.
- Relief may also come in the form of better management of air quality issues whereby reductions in emissions of another party underwritten by a prospective driller will be credited to the driller.
- Relief from restrictions may come in reducing the cost of obtaining rights to develop gas resource minerals by abolishing "combined hydrocarbon" leasing, which forces lessees to incur expenses for

de minimis value shallow tar sands in order to have rights to gas resource at deeper horizons.

The goal of such relief is to provide consistent land administration among federal and state agencies in order to provide access to the natural gas resource base that has been effectively placed off-limits by moratoria and other restrictions.

1999 Study Access Issue Sensitivities

To illustrate the potential for a more cooperative atmosphere for natural gas producing sector activity, and the detriment if current increasingly restrictive trends persist, two access sensitivity cases were crafted by the Supply Task Group: "Increased Access" on the one hand and "Reduced Access" on the other hand. Reference, Increased Access, and Reduced Access model assumptions are shown in Table S-9. Table S-10 illustrates the details of these restrictions by Rocky Mountain basin and resource type.

Although access is already very restricted in areas such as the Eastern Gulf of Mexico and the U.S. coasts, further restricting access to resource development in the U.S. onshore and offshore had a noticeable decremental impact. Production was reduced by more

TABLE S-9

SUMMARY OF NPC FEDERAL LANDS AND WATERS ACCESS SENSITIVITIES

	Reference Case	Increased Access Case	Reduced Access Case
Rocky Mountains			
Standard Lease Terms	59%	59%	22%
Off Limits	9%	9%	14%
High Cost	32%	32%	64%
High Cost Penalty per Well*	6% of Well Costs	0%	6% of Well Costs
High Cost Delay	2 Years	None	2 Years
Eastern Gulf of Mexico			
Destin Dome	No Development	Production by 2002	No Development
MMS Lease Sale 181	Lease Sale in 2001	Lease Sale in 2001	No Sale
Non-Sale 181 Eastern Gulf	No Sale or Development	Lease Sale in 2004	No Sale or Development
Other Offshore U.S.			
Pacific	No Development	Lease Sale in 2004	No Development
Atlantic	No Development	Lease Sale in 2004	No Development

*Estimated to be approximately $25,000 per well.

TABLE S-10

ROCKY MOUNTAIN REGION ACCESS SENSITIVITIES
RESOURCE BASE CATEGORIZATION BY PERCENTAGE

	Reference and Increased Access Cases				Reduced Access Case			
	Normal	High Cost	No Access	Total	Normal	High Cost	No Access	Total
Nonconventional Resource – Basin Level Specifications								
Uinta-Piceance	62%	29%	9%	100%	28%	58%	14%	100%
San Juan Basin	71%	23%	6%	100%	45%	46%	9%	100%
Powder River Basin	96%	3%	1%	100%	92%	6%	2%	100%
Wind River Basin	73%	22%	5%	100%	48%	44%	8%	100%
Green River Basin	55%	33%	12%	100%	16%	64%	20%	100%
Denver Basin	100%	0%	0%	100%	100%	0%	0%	100%
Raton Basin	98%	1%	1%	100%	96%	2%	2%	100%
Conventional New Fields – Aggregate	55%	35%	10%	100%	15%	70%	15%	100%
Old Field Reserve Appreciation – Aggregate	60%	40%	0%	100%	20%	80%	0%	100%

Note: Basins that were evaluated but that do not contain nonconventional gas resources in the Hydrocarbon Supply Model include the Paradox Basin, Montana Thrust Belt, North Central Montana, Williston, Big Horn, and Wyoming Overthrust.

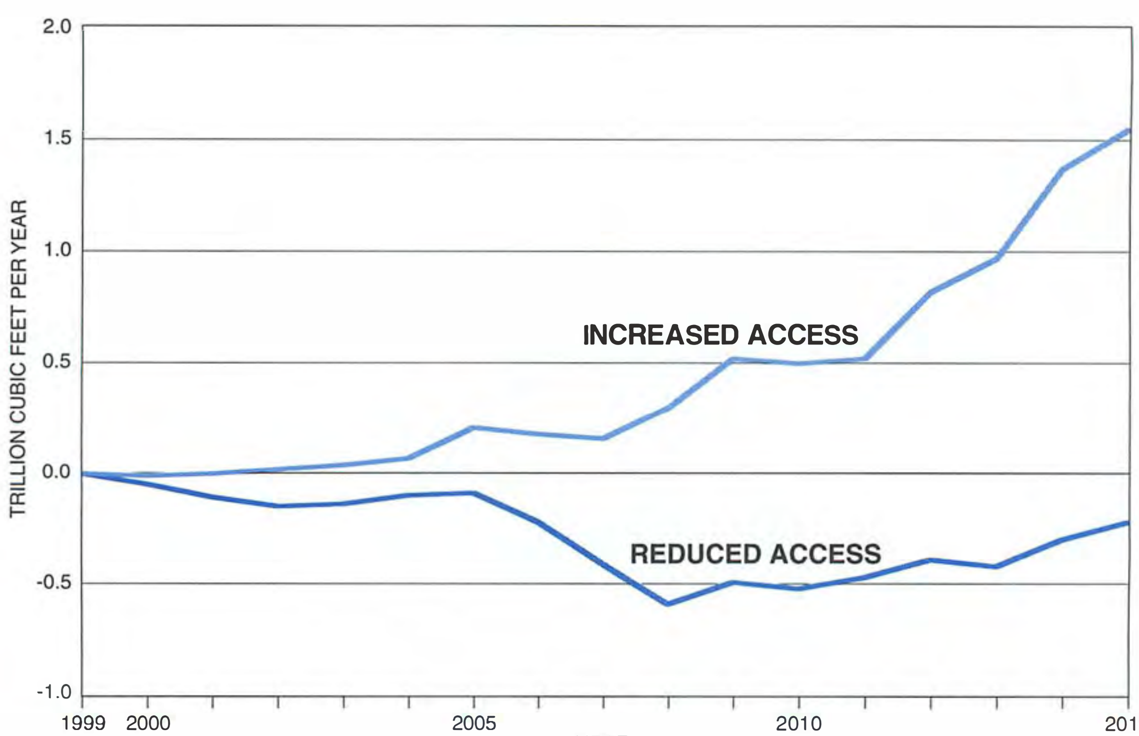
than 0.5 TCF per year in 2010 by tightening access restrictions—with a corresponding increase in 2010 Henry Hub natural gas price of $0.16 per million British thermal units (MMBtu). A model scenario relaxing access restrictions in the Rockies and offshore resulted in a converse impact, increasing production by 0.5 TCF per year in 2010—with a corresponding decrease in 2010 Henry Hub natural gas price of $0.22 per MMBtu. However, the increased access scenario had a much more dramatic impact after the year 2010—by 2015, production was nearly 1.5 TCF greater than Reference Case production and Henry Hub natural gas price was $0.45 per MMBtu lower. The impact beyond 2010 is much greater because the assumptions in the scenario only allow leasing in most of the currently restricted offshore areas to begin after 2004; thus, substantial development does not commence in earnest until late in the next decade, with production coming on-line between 2010 and 2015.

Production increases or decreases relative to the Reference Case in the Increased Access and Reduced Access cases, respectively, are portrayed in Figure S-5. This sensitivity analysis provides some insight into the impact of access issues in the Rockies, Eastern Gulf of Mexico, and the Pacific and Atlantic offshore regions. Access issues may serve to constrain or open opportunities for the natural gas exploration and production (E&P) sector to explore for, develop, and produce this important resource base. Restraining unreasonable access restrictions will accelerate the timing for bringing these resources to markets both enhancing reliability of natural gas supplies and improving the competitive position of natural gas relative to the price of other less environmentally friendly fuels. Finally, large untapped reservoirs, robust resource base size, and proximity to infrastructure of the Rockies and Eastern Gulf of Mexico make greater access to these resources an important complement to the producing sector's efforts to restore its financial health.

Increased Access Sensitivity

An "Increased Access" sensitivity case was run to evaluate the potential impact of improved access to onshore and offshore fed-

Figure S-5. Effect of Access Restrictions on U.S. Gas Production



eral lands. Onshore lower-48 access restrictions are primarily found in the Rocky Mountain region, while most offshore areas outside of the Central & Western Gulf of Mexico have been placed off-limits through moratoria.

In the Reference Case, 9% of the resource base in the Rockies is "No Access," while 32% is subject to higher costs as a result of access restrictions. The Increased Access case assumes that the same percentages of the Rocky Mountain resource base are off-limits and higher cost, but the high-cost penalties and delays are removed. In the Reduced Access case, the amounts of restricted acreage are increased, and the cost penalties are the same as in the Reference Case.

In the Eastern Gulf of Mexico, the Reference Case assumes that the Destin Dome gas project is not allowed to go forward. In the Increased Access case, activity is allowed to begin in the year 2002. MMS Lease Sale 181 is allowed to take place in 2001 as in the Reference Case. Eastern Gulf areas outside of the Lease Sale 181 area are off-limits in the Reference Case, but are opened up to drilling starting in 2004 in the Increased Access case.

The Atlantic and Pacific offshore areas are currently under moratoria and are held off-limits in the Reference Case. In the Increased Access Case, these areas are opened to exploration starting in 2004. The resource base volumes assumed for these areas are those developed by the Minerals Management Service in their 1996 assessment.

The Increased Access case yielded a net increase U.S. production of nearly 0.5 TCF per year in 2010 and more than 1.5 TCF per year by 2015. In this scenario, only three regions are expected to experience net increases in 2010 production relative to the Reference Case—the Rockies, the Eastern Gulf of Mexico, and the Pacific Offshore. Of those 2010 production increases relative to the Reference Case, Rockies and Eastern Gulf account for 95%. By 2015, Atlantic Offshore is added to the Rockies, Eastern Gulf, and Pacific Offshore, with production increases relative to the Reference Case; however, the Rockies and Eastern Gulf of Mexico continue to account for 82% of production gains in these four regions with growth by 2015. Henry Hub natural gas prices decrease in this scenario by $0.22 per MMBtu in 2010 and $0.45 per MMBtu in 2015 relative to Reference Case prices.

Reduced Access Sensitivity

A "Reduced Access" sensitivity case was developed to evaluate the potential impact of even greater access restrictions than are currently in effect. In the Rockies, an assumption was made that the portion of the gas resource base that is inaccessible increases by more than 50%, from 9% to 14%. The portion of the Rockies resource base experiencing higher costs doubles from 32% to 64%. In this scenario, the portion of the Rockies resource base that is unaffected declines to only 22%. The cost increase and project delays associated with the high cost portion of the resource are the same as in the Reference Case.

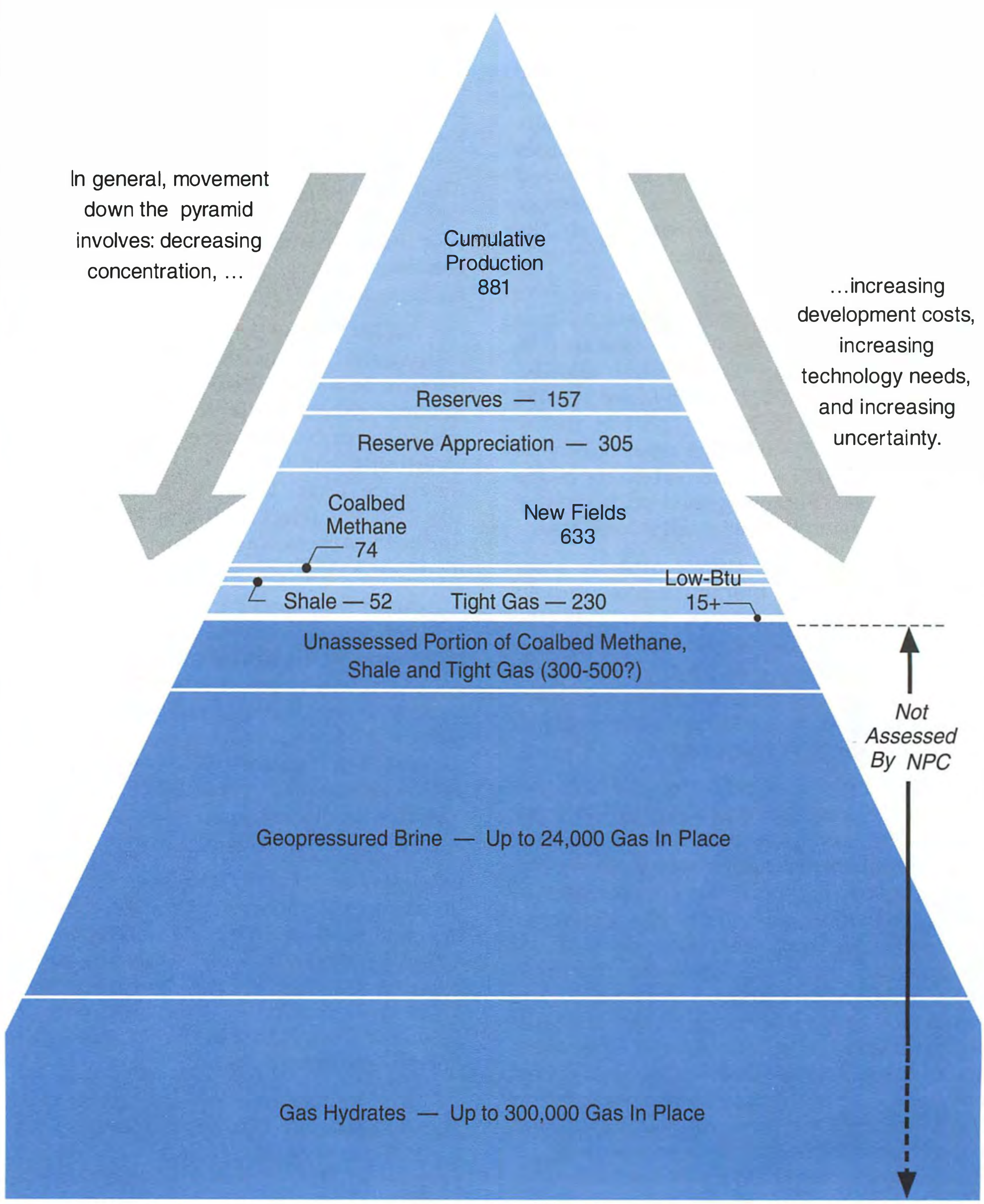
Tables S-9 and S-10 summarize the access restrictions on the Rocky Mountain gas resource base in the Reference Case and in the Reduced Access sensitivity. The total natural gas resource base assumed for the Rockies, Overthrust, and San Juan is 341 TCF. In the Reference Case, 29 TCF is off-limits and 108 TCF is subject to higher costs. In the Reduced Access case, these volumes are increased to 46 TCF and 216 TCF, respectively.

Table S-10 shows the restriction percentages for nonconventional resources in specific basin areas in the Rockies. These percentages were developed as part of the NPC study by looking at the distribution of U.S. Geological Survey (USGS) plays relative to land classifications. The high-cost and no-access percentages were applied to the NPC gas resource base in each of these areas.

The Eastern Gulf of Mexico, Atlantic Offshore, and Pacific Offshore remain off-limits to exploration in this case. The only lower-48 offshore area to be developed is the Central & Western Gulf of Mexico and the western portion of the Norphlet Trend. Therefore, the only difference with the Reference Case is that MMS Lease Sale 181 is not allowed to take place.

The Reduced Access case resulted in a net decrease in U.S. production of over 0.5 TCF per year in 2010 and nearly 0.25 TCF per year in 2015. The net decrease is less dramatic than increases in the Increased Access scenario primarily because Reference Case

Figure S-6. The Lower-48 Gas Resource Pyramid
1999 NPC Assessment
Recoverable Portion of In-Place Gas Resource – Trillion Cubic Feet



access assumptions are already very restrictive. In this scenario, the great majority of production declines relative to the Reference Case occur in the Eastern Gulf of Mexico and the Rockies. This scenario yields 2010 declines of over one BCF per day in each of the Rockies and the Eastern Gulf of Mexico—modest net increases in a variety of other basins offset a small portion of this decline. This scenario also results in 2015 declines of over one BCF per day in the Eastern Gulf of Mexico with some of this offset by net increases in a variety of other basins. Henry Hub natural gas prices increase in this scenario by $0.16 per MMBtu in 2010 and $0.08 per MMBtu in 2015 relative to the Reference Case prices.

Lead Time

Related to concerns for access to resource-bearing public lands is the effect of moratoria and other restrictions on lead times experienced to develop key resource basins. When considering supply and demand balances, one must also consider the time necessary to bring newly discovered gas to market. This is true in established areas such as the Gulf of Mexico. For example, once commercial quantities of hydrocarbons are found in Gulf of Mexico deepwater fields, approximately five years elapse before the natural gas is brought to market. Thus, a major discovery announced today will not be available for consumption until 2005. Because nearly 15% of the gas supply in the year 2010 is expected to be from this region, it is critical that delays in exploring for, and development of, these resources be kept to a minimum.

Much of our natural gas supply needs after 2015 will come from frontier areas or offshore areas that are currently off-limits to exploration. Lead times to bring gas to market from such areas as the Mackenzie Delta in Canada have been estimated at ten years, seven years in the most optimistic predictions. Often these delays are due to permitting, impact studies, legal entanglements, and other issues not directly related to bringing natural gas to market. As a greater need for these resources develops, lead times for development will be an even more important issue.

Lead time will continue to be a key consideration beyond 2015 for far frontiers such as Alaska and the Canadian Arctic, as well as high cost resources shown in Figure S-6. These resources will be important for long-term sustainability of natural gas production. Lead time to access, develop, and bring these resources to market is discussed in detail in Appendix J. Also included in Appendix I are discussions of expanding imports of LNG and Mexican gas, as well as producing gas from geopressured brine and hydrates.

Summary

Access to areas containing additional natural gas resources base is critical to attaining the goal of adequate supplies of clean-burning natural gas to meet increasing energy demand and achieve air-quality standards. Access is also important to maintain gas prices that will not have a detrimental impact on economic growth and prosperity. Executive Branch agencies will be important players in fostering cooperation among all stakeholders. Inherent friction between the natural gas producer and environmental groups must be replaced by a sense of shared opportunity to greatly improve air quality as natural gas expands its role as the preferred fuel for supporting growth in electric power demand. Legislators will also be instrumental in providing clarifying language to ensure that Executive agencies are not hamstrung by vague statutory provisions that create excessive avenues for expensive and protracted litigation by anti-development special interests. Similarly, legislation supported by clear Executive backing is needed to definitively state public policy regarding natural gas development as a, if not *the*, key means in the next decade to achieve clean air objectives.

Chapter Three

A Healthy Oil and Gas Industry is Critical for Natural Gas Supply to Satisfy Expected Increases in Demand

Adequate Financial Performance Must be Demonstrated to Compete For and Attract Financial Investment

The growth in gas demand projected in the 1999 Study will require nearly $1 trillion (1998$) in upstream expenditures from 2000 through 2015 in the United States alone. A summary of estimated U.S. expenditures required over this period is shown in Table S-11.

In 1998$, this growth in demand will require yearly average industry expenditures of $60 billion from 2000 through 2015, versus an annual average of $52 billion from 1991 through 1996. Figure S-7 shows the annual projection of industry expenditures.

TABLE S-11

ESTIMATED U.S. EXPENDITURES*
1999 THROUGH 2015
(Billion of 1998 Dollars)

Operating Costs	$ 362
Capital Expenditures	$ 658
Total Expenditures	**$1,020**

*Includes gathering costs.

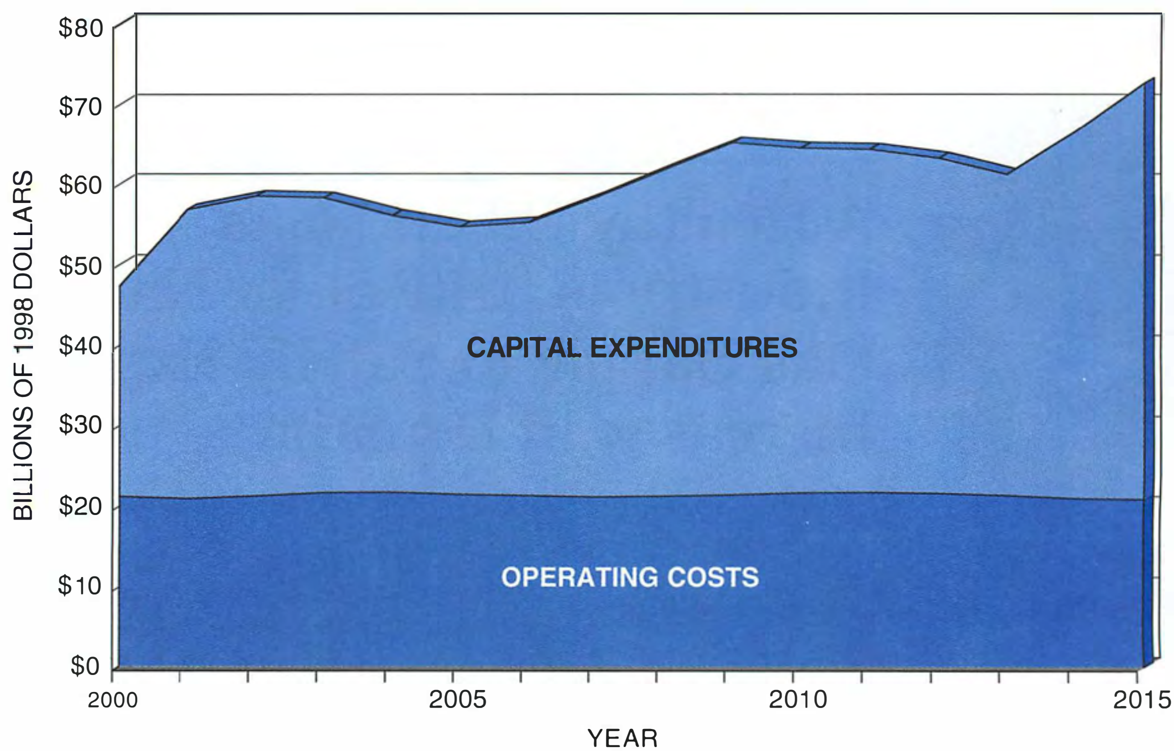
These needed levels of investment will take place only if investors believe that adequate rates of return will be earned. In the last 12 years, the U.S. upstream sector has earned very modest rates of return. According to EIA's Financial Reporting System (FRS), the 23 largest producers reported a straight average return on assets of under 5.5% over the 12-year period from 1986 through 1997.

As Figure S-8 illustrates, upstream rates of return have a strong positive correlation with oil prices. Post-1993, with a less-regulated post- FERC-Order-636 natural gas market, upstream returns on investment have also developed a strong positive correlation with gas prices.

During the 12-year period from 1986 through 1997, 1997 marked the only year where returns of those 23 companies' producing subsidiaries exceeded in double-digits (i.e., greater than 10%) the returns of non-energy affiliates, as shown in Figure S-9. In fact, over the past 12 years, a straight average of non-energy affiliate returns has been 10.7%—nearly double the straight average return on investment of the oil and gas producing affiliates.

The producing company double-digit returns of 1996 and 1997 were unique; daily cash West Texas Intermediate (WTI) oil prices averaged $22.16 and $20.61, respectively, for each of these years. These average annual prices are significantly greater than future

Figure S-7. U.S. E&P Expenditures 2000–2015



WTI average annual price expectations on which the 1999 Study based its findings. While aggregate producing company returns on investment are currently unavailable for 1998, daily cash WTI oil prices for 1998 were lower and averaged $14.39.

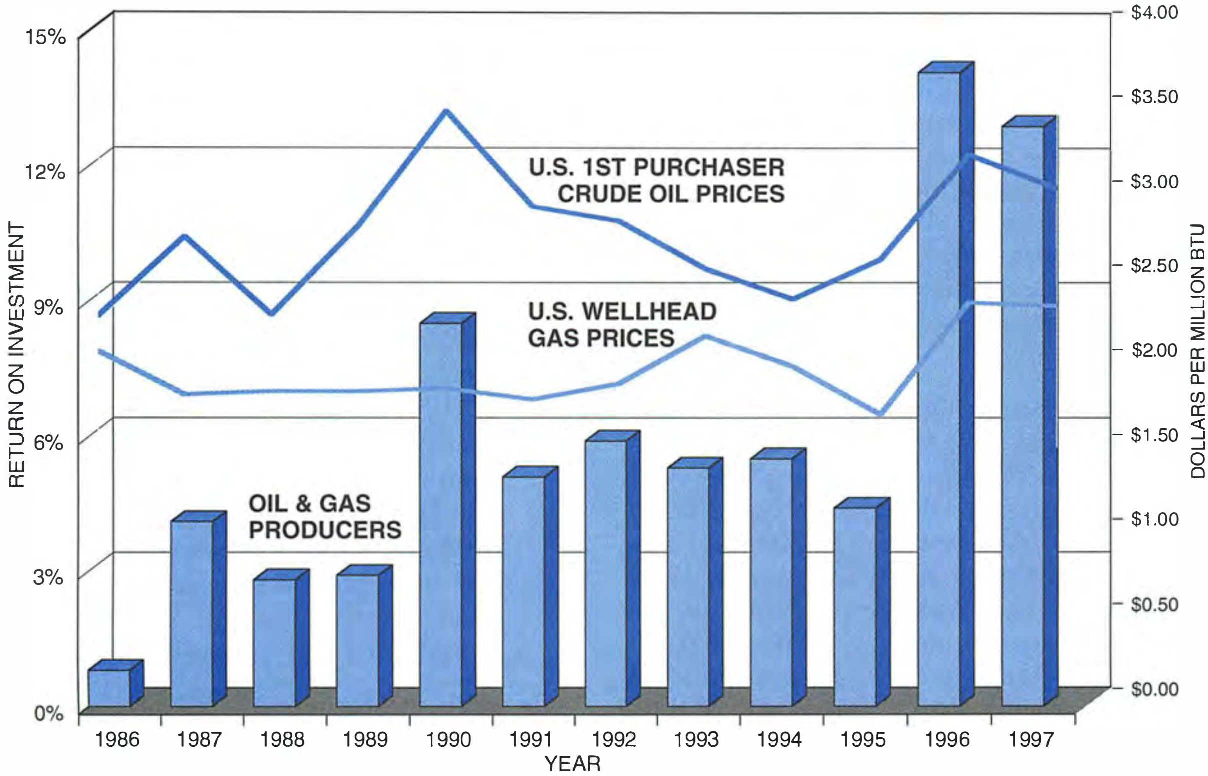
Historical low rates of return and the magnitude of price volatility jeopardize the steady flow of capital that is needed to achieve the large projected increases in gas production required to meet growing demand.

Aggressive Pro-Active Workforce Planning is Essential

Without immediate action, impending shortages of qualified personnel are expected to hinder the ability of the producing sector to find and develop required gas supplies. Three major shocks to employment prospects in the producing sector have occurred in the last 20 years. Each of these shocks (1982, 1986, and 1998) was caused by drastic declines in the world market price of crude oil and resulted in significant reductions in expenditures and jobs. At the same time, companies dramatically decreased hiring rates. Employment prospects over the next 10 years will likely rival those of the late 1970s in the producing sector. The volatile history of producing-sector employment has already begun, and is expected to continue, to hinder the ability of the producing sector to attract and retain the numbers of qualified personnel needed to explore for, locate, drill, and produce the natural gas needed to satisfy the expected growth in demand.

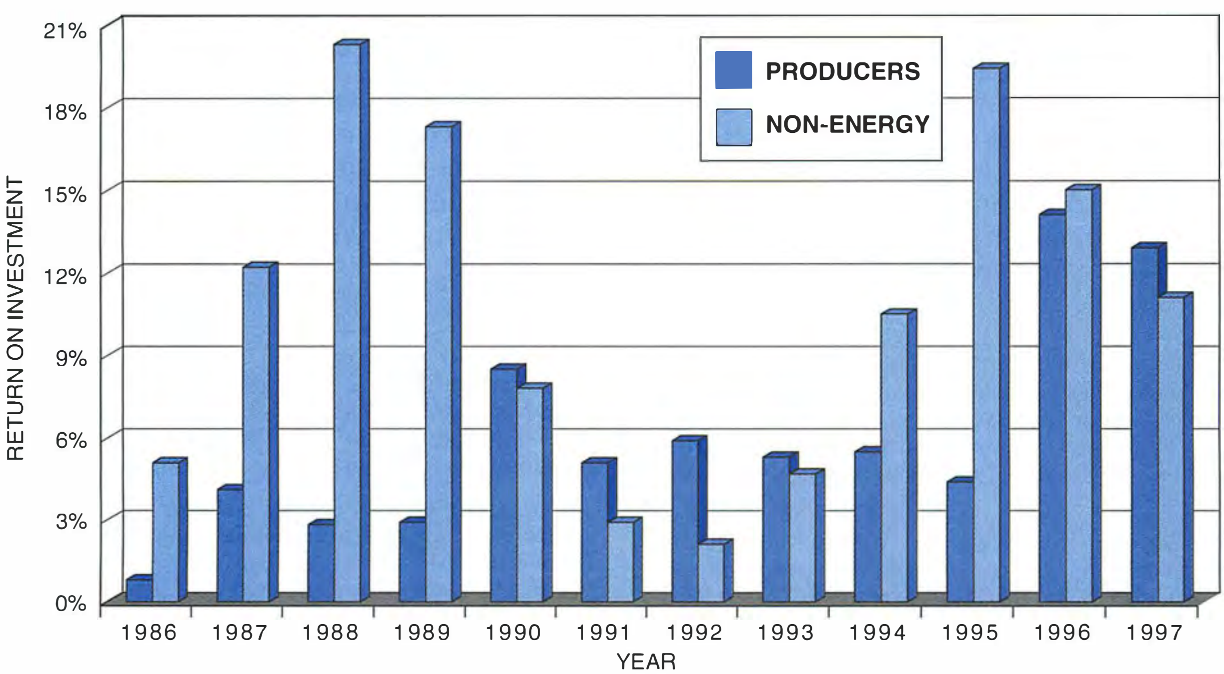
In the aftermath of precipitous declines in crude oil prices in 1981, enrollments in key disciplines that support the producing sector began to decline drastically and gained momentum with a subsequent and equally devastating oil price drop in 1986. The "farm clubs"—college and university petroleum engineering and geoscience degree programs—continue to have great difficulty attracting promising high school seniors. Enrollments in undergraduate petroleum engineering and geoscience programs have declined by 77% and 60%,

Figure S-8. Rates of Return and Commodity Prices
Oil & Gas Producers, 1986–1997



SOURCE: EIA Performance Profiles of Major Energy Producers, January 1999.

Figure S-9. Rates of Return, 1986–1997
Oil & Gas Producers vs. Non-Energy



SOURCE: *EIA Performance Profiles of Major Energy Producers*, January 1999.

respectively, between 1985 and 1998 (Figures S-10 and S-11).[1]

Likewise, skilled trades supporting the producing sector also have suffered from these industry cycles. The oilfield service/supply sector faces similar challenges in meeting engineering and operations requirements. Volatility in the drilling industry has caused many skilled rig operations personnel to leave the industry in search of more stable careers. Industry contractors will be challenged to find and train adequate numbers of skilled laborers, such as machinists, electricians, pipefitters, and welders.

The 1999 Study Reference Case indicates that the number of gas wells drilled in the United States will grow during the next decade from roughly 11,600 in the year 2000 to 16,500 in 2010. The last time 16,500 gas wells were drilled in the United States was 1982. Between 1982 and 1998, employment in the producing sector declined by almost 400,000 jobs.[2] A snapshot of the decline in producing sector employment during that period of time is illustrated in Figure S-12.

An additional 50,000 jobs were lost in the latest downturn between late 1997 and early 1999.[3] And, by one modeling estimate, employment in the producing sector may decline from roughly 325,900 in 1998 to approximately 273,000 in 2000.[4] Technological advancements can be expected to continue to increase productivity in the producing sector from 2000 to 2010. However, a 42% growth in the number of gas wells drilled in the next decade means a vast increase in prospects that will need to be generated (geoscientists), drilled (engineers and rig hands), and completed and hooked up (engineers and field personnel). Current enrollment trends in producing-sector college disciplines and employment trends in related skilled trades are insufficient to even replace individuals lost to normal retirement.

A few items of anecdotal evidence that this concern is already an issue are important to note:

- In 1984, 425 undergraduate degrees in total were awarded in petroleum engineering at six of the dozen schools historically noted for producing the largest number of petroleum engineering graduates.[5] In 1996, graduation figures from these same six universities had decreased to 117 undergraduates in petroleum engineering. In December 1997, one major company indicated that it was looking to hire 200 petroleum engineering from the 1998 graduating classes. If this company had been able to hire all 1998 graduates from the six leading universities,[6] it would have fallen short by at least 25%.[7]
- With the recovery in oil prices throughout 1999, exploration activity has begun to rebound. An informal phone survey of three oilfield service companies revealed the following labor shortages:
  - One company indicated that it is attempting to hire more rig hands due to the fact that with 110% utilization of its workforce, only 40% of its rigs can be mobilized.
  - A Permian Basin drilling company faced with a similar challenge to hire more qualified workers stated that it is offering $10 to $25 per hour bonuses as it copes with 100% utilization of its

[1]Data from (1) *Petroleum Engineering and Technology Schools 1997-98*, Society of Petroleum Engineers, www.pe.ttu.edu/spe_schools_book/html/school.html; and (2) American Geological Institute, *Survey of Students in the Geosciences, 1985-1986 through 1998-1999.*

[2]Department of Energy, Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1999*, p. 48, "Employment in Oil and Gas Extraction," James M. Kendell.

[3] Ibid, p. 47.

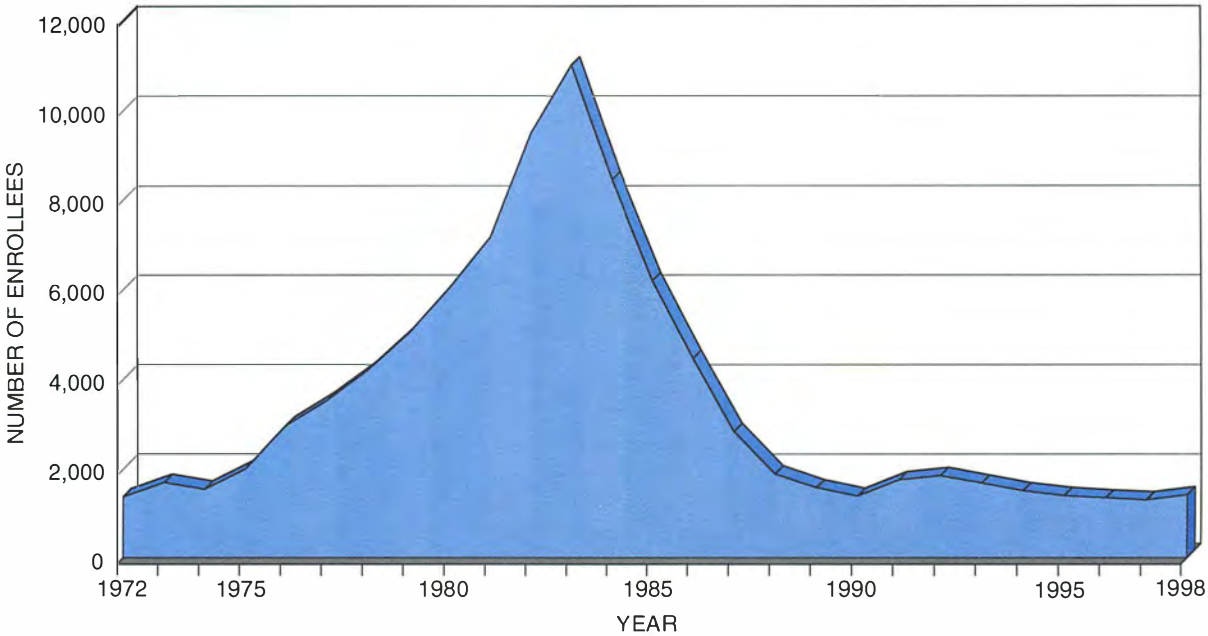
[4] Ibid, p. 47.

[5]*Oil & Gas Executive*, "Achieving Excellence: Dialogue with Two at the Top," June 1998, p. 36 (Texas A&M University, Colorado School of Mines, University of Texas, Louisiana State University, University of Oklahoma, and the University of Missouri at Rolla).

[6]In 1998, the top six schools by number of petroleum engineering enrollees were Texas A&M University, Montana Tech, University of Texas, Texas Tech, Louisiana State University, and Colorado School of Mines. *Petroleum Engineering and Technology Schools 1997-98*, Society of Petroleum Engineers, www.pe.ttu.edu/spe_schools_book/html/school.html.

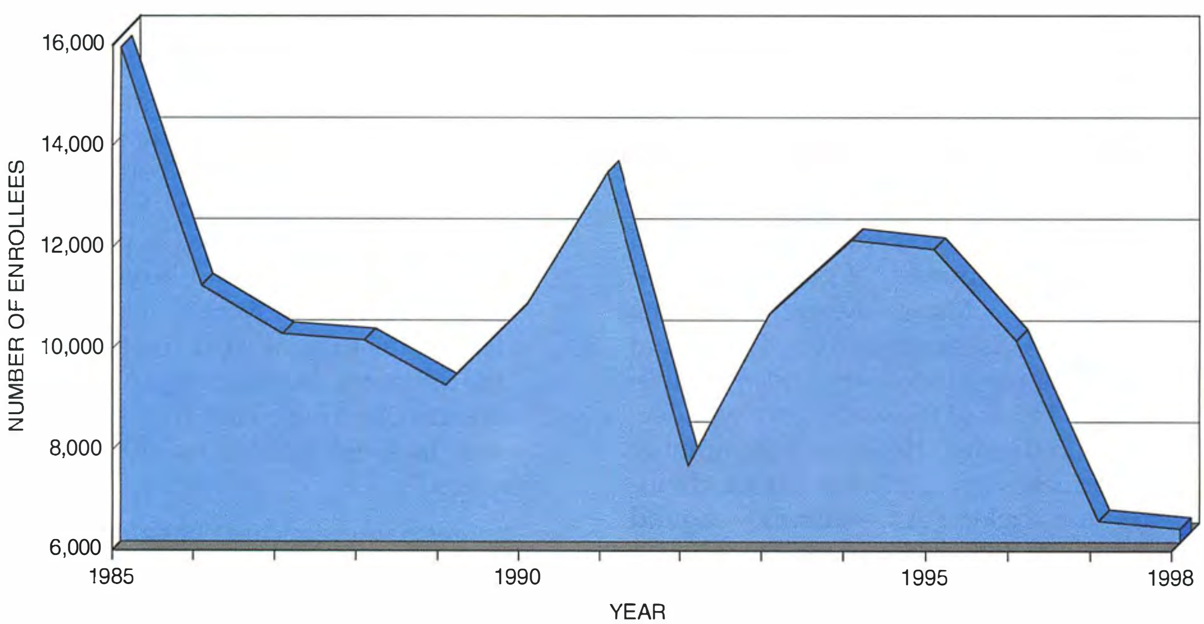
[7]Ibid, Footnote 7.

Figure S-10. Total U.S. Undergraduate Petroleum Engineering Enrollees



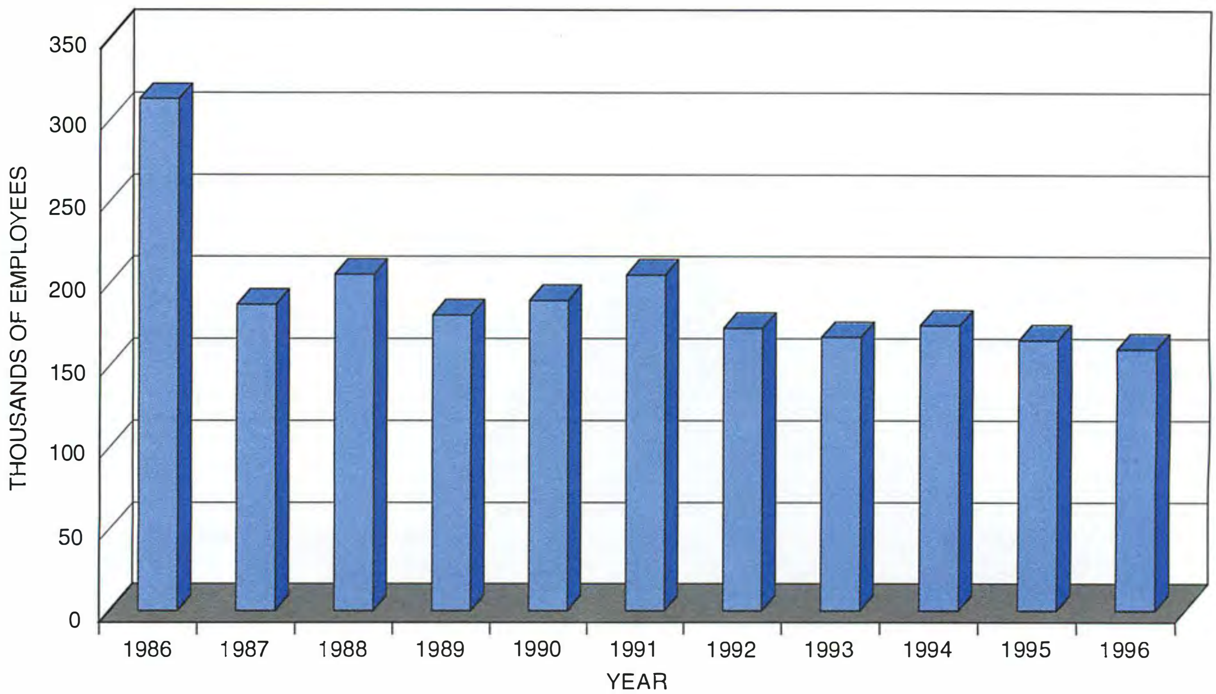
SOURCE: Society of Petroleum Engineers, *Petroleum Engineering and Technology Schools 1997-1998.*

Figure S-11. Geoscience Undergraduate Enrollments, 1985–1998



SOURCE: American Geological Institute, *Survey of Students in the Geosciences, 1985–1986* through *1998–1999.*

Figure S-12. U.S. Employees in Oil & Gas Extraction Activities, 1986–1996



SOURCE: *Offshore*, February 1997 (citing U.S. Bureau of Labor Statistics).

workforce, which is able to mobilize only 30% of the company's rigs.

- A Gulf Coast-based services company that reacted to the 1998 downturn by laying off 450 of its workers indicated that it recently attempted to hire back the top 100 performers from that group. The company received only two responses to these inquiries, and both individuals declined the company's offer.

- In its April 1999 report of the 1998 Annual Salary Survey of geologists (conducted by MLA Resources), the American Association of Petroleum Geologists reported in its *Explorer* publication: "Much of the work force was decimated in the mid-1980s, and the number of graduates available for hiring dwindled to a trickle. An economic rebound from 1994-1997 drew more students to the field, but the competition to hire the top students also caused salaries to rise as well. The 1997 salary survey noted a 'hiring frenzy,' and reported employment bonuses to new graduates of up to $50,000 a year with a company car. [Spokesman for MLA] said now that on-campus recruiting 'has slowed appreciably.' There are also reports of at least one major company retracting offers made to spring and fall graduates. There are many interesting implications to the actions that companies are taking, [MLA spokesman] said. 'Over the course of the last decade and a half, upstream professionals have been trained to believe that after they turn 50 they'll get an early retirement package and leave,' he noted. If that perception were to become reality, 90% of the present work force could leave the industry in the next 10 years—and about 65% in the next five years due to the lack of hiring in the 1986-1996 years."[8]

Other paradigms are changing regarding the professional and skilled trades workforce

[8]www.aapg.org/explorer/archives/04_99/salary survey.html

in the producing sector. Historically, companies understood that new-hire engineers required substantial training and utilized in-house training programs, apprenticeships, and/or consultants and service companies over a period of years to fill the knowledge gap. With thin "bench strength" and a dwindling cadre of mentors, the new hire is more likely to be deprived of the opportunity to gain much-needed experience. The good news for the new graduate is that he or she must no longer bide time and build managers' confidence before receiving higher-potential assignments. The bad news is that these higher-potential assignments are of equally higher risk and are being managed by individuals with infinitely less experience than such prospects would have merited in the past. A recent article in *Journal of Petroleum Technology* stated the issue as follows:

> As the mid-1990's started . . . [c]ompanies recognized their manpower pools were aging and that there was a limited market of good experienced engineers. Hiring increased. But the paradigm of the oil-boom times was still entrenched – all engineers eventually could be trained as a petroleum engineer. Except that, now, there were no mentors or training programs and no dog wells or fields to experiment on . . . .
>
> The real cost of training engineers . . . is the cycle time to get an engineer "capable" in this new high-tech business . . . [i]t takes long-term strategies and plans, not year-to-year reaction to cycles of oil and gas prices. Educators and industry must learn a new way of working together.[9]

Beginning immediately, aggressive pro-active workforce planning is a necessity for producers and contractors to achieve staffing levels that are necessary to meet the challenge of supplying natural gas demand that is expected to increase by nearly 30% over the next ten years.

New Drilling Rigs Must Be Built

Overview of Rig Needs

The U.S. drilling fleet must expand to undertake the dramatic increase in activity that will be required to produce the additional gas supplies anticipated in this study. The number of wells drilled annually is projected to more than double, from roughly 24,000 in 1998 to over 48,000 by 2015. This amount represents total wells drilled (including both gas and crude oil wells plus dry holes). Because roughly 15% of natural gas consumed in the United States is produced from oil wells (so-called "associated-dissolved gas") oil well drilling must be taken into account when considering the drilling needs for increased gas supply. Even taking into account anticipated improvements in drilling efficiencies of between 1.25% and 1.50% per year, approximately 2,300 active rigs (over 2,100 land rigs and 180 offshore) would be needed to achieve the projected level of drilling. This represents a 60% increase over the 1,250 average rig count estimated for 1999.[10]

Providing these rigs, and the crews to operate them, will be a challenge for the industry. The oilfield supply and service sectors have been hit particularly hard by the boom and bust cycles. Very few new onshore drilling rigs have been built since the mid-1980s. If the 5% per year historical attrition rate were to continue, most of the existing 1,700 onshore rigs would be retired by 2015 and a total of almost 1,900 onshore rigs would have to be built. The cost of these new onshore rigs would be over $12.4 billion (1998$). Additions to the offshore fleet are projected to include 10 deepwater drilling rigs, 32 platform rigs, and 30 jack-up rigs and barges. Although fewer new offshore rigs need to be built compared to onshore rigs, the cost per offshore rig is an order of magnitude higher. The capital cost of the new offshore rigs projected to be needed would be $7.3 billion (1998$) if all the additional rigs came from new construction.

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[9] Keith K. Millheim, "Fields of Vision," *Journal of Petroleum Technology*, October 1999, p. 14.

[10] Unless otherwise stated, all rig counts are on a "Reed Oil Tools" basis, adjusted for shallow-drilling, truck-mounted rigs.

Rig Statistics

Several sources are available for rig statistics, each with its own purposes and definitions. The oldest and most often quoted rig statistic is the weekly Baker Hughes operating rig count. Baker Hughes is a drill bit manufacturer that began this survey in the 1930s as an in-house tracking and marketing tool. The weekly Baker Hughes survey covers rotary rigs that are "turning to the right," so it doesn't cover contracted rigs that are moving between jobs, rigging up, or completing wells. For the year 1997, the average number of onshore rigs operating in the United States was 821 according to the Hughes survey.

Another weekly survey has been conducted since 1982 by Smith Tools International, also a drill bit manufacturer. An active rig is defined by Smith as one that is either drilling, rigging up, fishing, testing, or at total depth. Smith and Baker Hughes weekly surveys track each other very closely. However, because of its more expanded definition of what rigs are covered, the Smith survey tends to report about 10% more rigs.

Both the Baker Hughes and Smith rig surveys are done weekly and are aimed at getting a picture of ongoing activity. Neither concerns itself with the state of the entire rig population, including inactive rigs. In contrast, the "Reed Rig Census" is done once each year and compiles data on "active" rigs and "available" rigs. The "Reed Rig Census" (as published in the October 1998 edition of *World Oil*) says that in 1997 there were 1,235 onshore active rigs out of 1,428 that were available, for a utilization rate of 86%. An active rig is one that was in use during the 45-day qualification period. An available rig is one that is being marketed or could be made available with an expenditure of $100,000 or less ($1 million or less for an offshore rig). Reed doesn't count rigs that have been stacked for more than three years, cable tool rigs, or rigs not drilling deeper than 3,000 feet.

Both the Hughes and Reed surveys miss truck-mounted rigs that are used to drill shallow wells. For example, in 1997 there were 556 wells drilled in the states of Illinois and Indiana (average depth 2,315 feet) but Hughes shows that there were no rotary rigs in operation. A similar problem exists in all of the Appalachian states, Kansas, and elsewhere where the number of wells and footage drilled are out of proportion to the Hughes rig counts. A reasonable estimate would be that an average of about 101 shallow, truck-mounted rigs would be "turning to the right" in 1997, meaning that a "corrected Hughes count" should be about 922 operating rigs.

The annual average Hughes operating rig count over the last several years has been 61% of the Reed active rig count. The major difference in the counts is that the "Reed Rig Census"—because of its longer eligibility period—picks up rigs that are moving between jobs or are completing wells in any given week. In 1997, the Reed active onshore rig count was 1,235. Adding another 233 rigs to account for shallow, truck-mounted rig brings the "corrected" total to 1,468.

Recent Onshore Rig Productivity

Table S-12 shows an estimate for 1997 of the number of rig days employed drilling onshore wells in the United States. The number of "corrected" Hughes rig days in 1997 was 922 rigs times 365 days equals 336,530 rig-days or 12.4 days per onshore well. The number of corrected Reed active rig days was 1,468 times 365 equals 535,820 rig-days or 19.8 days per well. The difference of 7 days per well represents, for the most part, mobilization and completion days. The total number of rig days (Reed active concept) needed per well are 8 days for the 0-5,000 foot interval, 21 days for 5-10,000 foot interval, 49 days for the 10-15,000 foot interval, and 107 days for the interval deeper than 15,000 feet. The bottom portion of Table S-12 shows approximate average day rates for 1997 and what the dollar amount implied for rig use by depth interval. Also shown is the rig cost in dollars per foot and the total well cost per foot as reported in the Joint Association Survey of Drilling Costs. The estimated rig component is about 25% to 28% of the cost of onshore wells.

The data in Table S-12 show that the days required to drill a well, and the well costs rise exponentially with depth. The reason for this is that the rate of penetration decreases with the added rock pressures and hardness encountered with increasing depth. This is illustrated in Figure S-13, which shows typical onshore incremental rates of penetration of 900 feet per day near the surface, declining to

TABLE S-12

ONSHORE U.S. RIG AND DAY RATE BALANCE: 1997

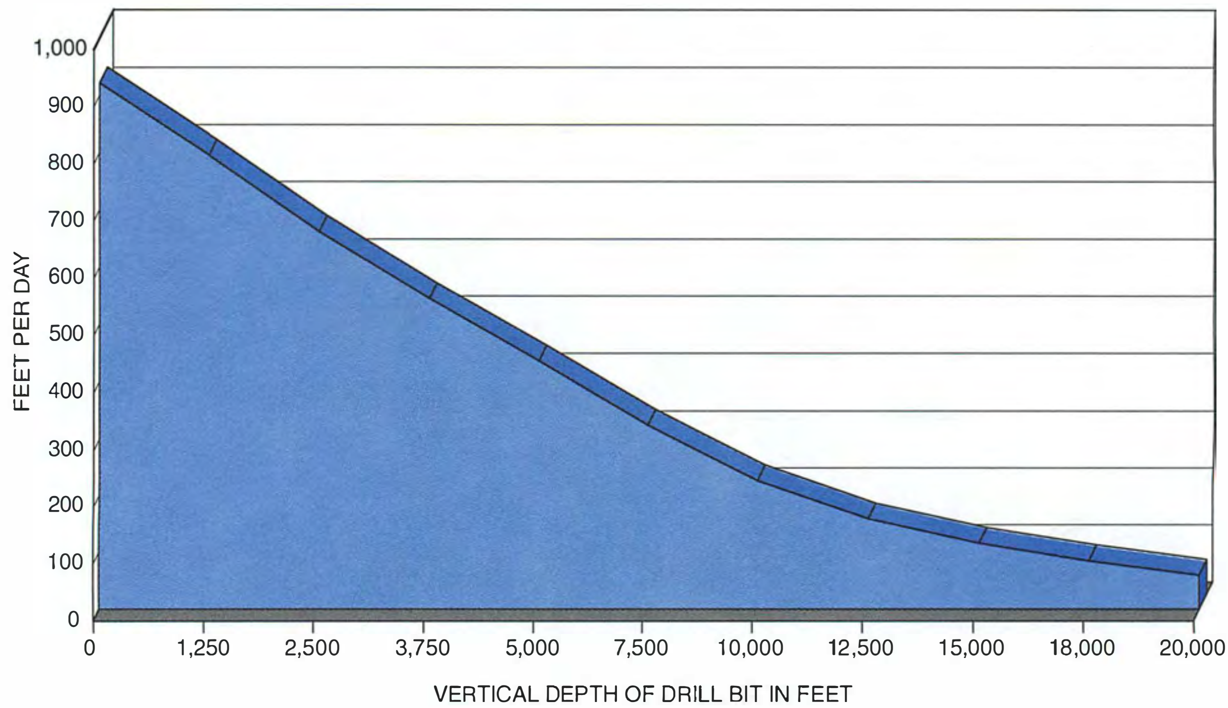
	Hughes Operating	Reed Active	Reed Available	Reed Utilization
Rigs Counted by Hughes & Reed	821	1,235	1,428	86%
Other (Truck Mounted)	101	233	270	86%
Total Rigs	**922**	**1,468**	**1,698**	**86%**

	0-5,000 ft Depth 1	5-10,000 ft Depth 2	10-15,000 ft Depth 3	>15,000 ft Depth 4	Total
Wells Drilled	13,661	9,254	3,527	614	27,056
Feet per Well	2,510	6,905	11,773	16,890	5,547
Total Footage	34,291,000	63,900,000	41,521,793	10,370,200	150,082,993
Non-Drilling Days/Well	4	8	15	29	7.37
Drilling ROP* (Feet/Day/Rig)	750	525	343	216	446
Drilling ROP* (Feet/Year/Rig)	273,783	191,765	125,108	78,907	162,819
All Rig Time (Reed Census Concept)					
Days per Well	8	21	49	107	19.8
Total Days	105,570	191,932	172,485	65,732	535,719
Active Rigs	289	526	473	180	1,468
Drilling Time Only (Hughes Survey Concept)					
Days per Well	3	13	34	78	12.4
Total Days	45,716	121,625	121,139	47,969	336,449
Operating Rigs	125	333	332	131	922
Ratio Hughes/Reed Concepts	0.43	0.63	0.70	0.73	0.63
1997 Day Rates ($/Day/Rig)	$4,500	$5,500	$7,000	$9,500	$6,277
Rig Revenue (Million $)	$475.1	$1,055.6	$1,207.4	$624.5	$3,362.5
$/foot for rig	$13.85	$16.52	$29.08	$60.22	$22.40
$/foot for well (JAS)†	$49.45	$62.49	$106.51	$244.35	$84.26
Rig cost as % of well	28%	26%	27%	25%	27%

*ROP = rate of penetration.

†JAS = Joint Association Survey of Drilling Costs.

Figure S-13. Incremental Rate of Penetration



below 100 feet per day at about 15,000 feet and below.

Projection of Future Onshore Drilling Activity

The number of onshore wells projected to be drilled under Reference Case conditions is shown in Figure S-14 by depth interval. The number of onshore wells drilled in 1998 and 1999 fell from about 27,000 wells drilled in 1997. Future activity is expected to rebound and reach about 36,000 wells in 2010 and over 47,000 wells in 2015.

The projected footage to be drilled onshore in the United States is shown in Figure S-15. Approximately 150 million feet were drilled in 1997. By the year 2010, this figure is expected to be 215 million feet and by 2015 nearly 270 million feet. Because the number of wells and the footage drilled is projected to grow fairly evenly across drilling depths, the average feet per well is expected to change only slightly as it maintains a range of 5,400 to 5,900 feet per well.

Onshore Rig Requirements

Given the projected drilling activity described above and the 1997 productivity estimates shown in Table S-12, and assuming a 1.25% improvement in efficiency, the required number of future active rigs was computed and the results shown in Figure S-16. From an active count of 1,468 onshore rigs in 1997, needs are expected to grow to 1,800 rigs in 2010 and 2,000 rigs by 2015. These active rigs projections are consistent with the Reed survey concept and include non-drilling time (rig mobilization, completions, etc.).[11]

Also shown in Figure S-16 is the projected number of "available" rigs that would be needed. Because some time is needed for rig maintenance and out-of-contract mobilizations, the number of active rigs cannot be equal to available rigs. The highest utilization rate recorded by the Reed Census was 98% in 1981. For purposes of this projection, it was

[11]The future operating rig count consistent with the Baker Hughes survey can be approximated by multiplying the active rigs in Figure S-16 by 0.61 (e.g., about 1,300 operating rigs in 2015).

Figure S-14. Onshore U.S. Well Counts by Depth Interval

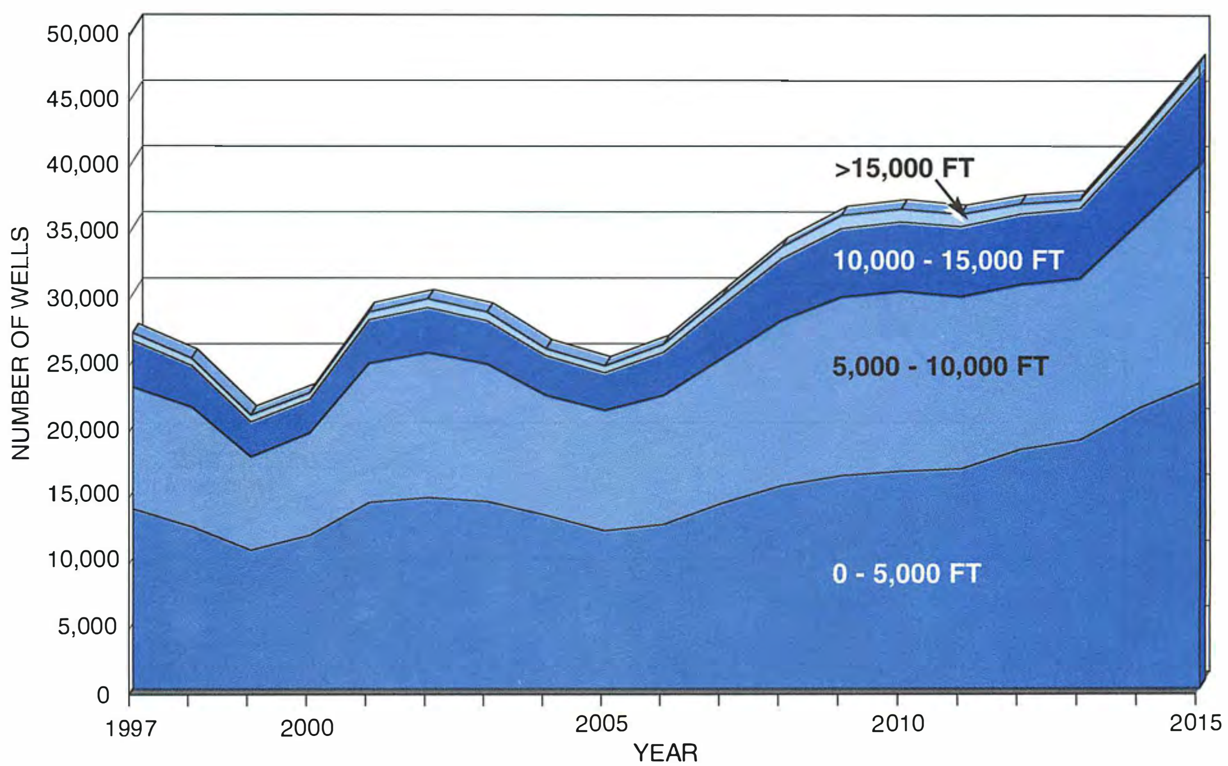


Figure S-15. Onshore U.S. Footage to be Drilled by Depth Interval

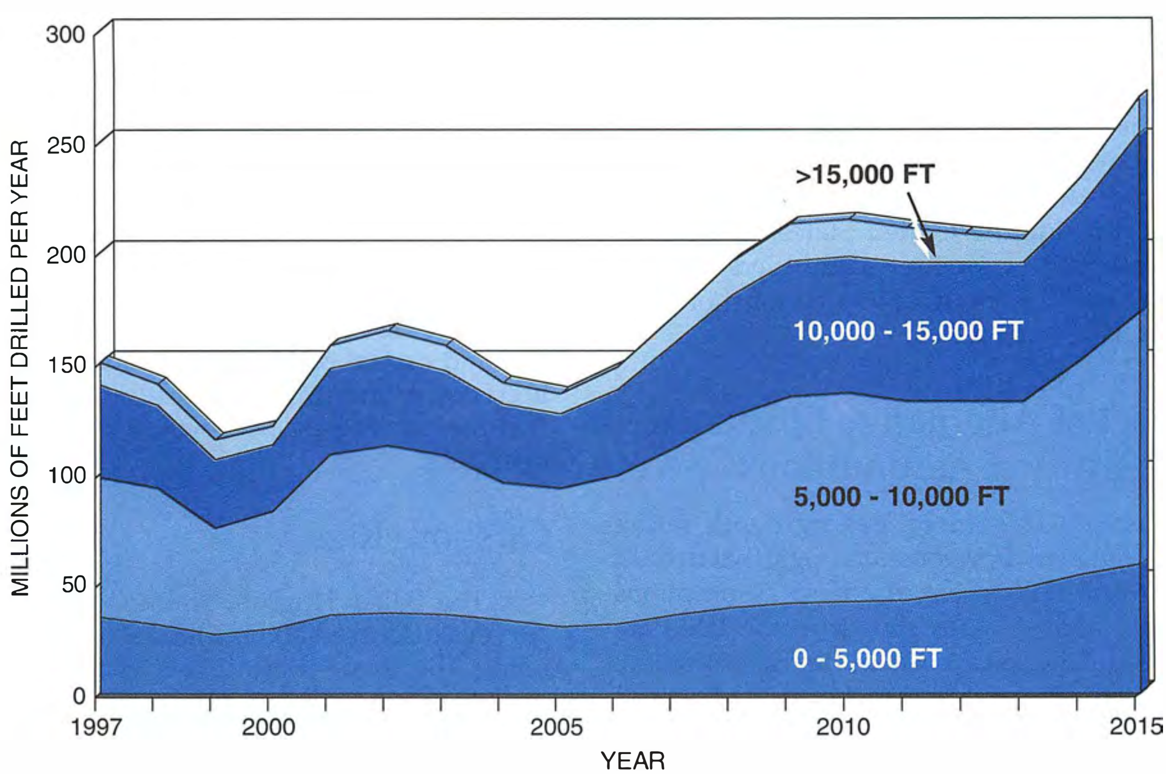
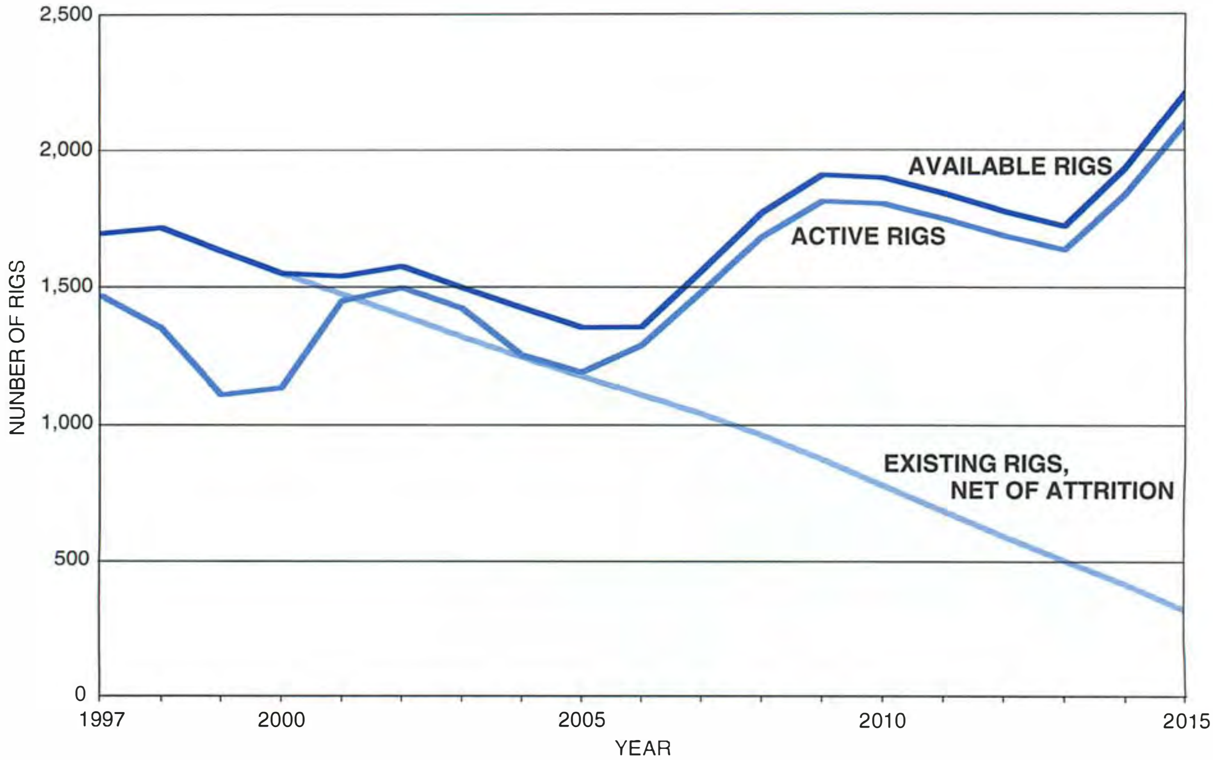


Figure S-16. Onshore U.S. Drilling Fleet, 1997–2015



assumed that the maximum sustainable utilization rate would be 95%.

The third line in Figure S-16 represents the current onshore rig fleet, net of attrition. The difference between this line and the "available" rig line represents new rigs that must be added. Over the last 10 years, a net annual average attrition of 5% of the rig fleet occurred. Rigs were retired, cannibalized, or moved outside the United States. Assuming that this rate of attrition continued into the future, by 2015 about 1,895 new onshore rigs would have to be added.

Impact of Alternative Efficiency and Attrition Assumptions

Table S-13 summarizes by depth rating the number of new onshore rigs that would have to be built given the base assumptions outlined above. Also shown in the table are the assumed capital costs of the rigs. In total, the 1,895 rigs projected to be needed would cost $12.4 billion (1998$) if all rigs were newly constructed.

The efficiency gain of 1.25% per year incorporated as a base assumption means that a deep well that took 107 days to drill in 1997 would take 85 days in 2015. If this assumed efficiency gain were cut in half to 0.75% per year, the number of new onshore rigs that would have to be built would increase to 2,240 and the construction cost would rise to $14.8 billion. If no efficiency gains were to take place at all, the new rig requirement would be 2,623 by 2015 and the capital costs would increase to $17.4 billion. On the other hand, if attrition rates were to average to just 2% per year, new rig requirements would fall to 1,211 rigs and capital cost would decline to $7.6 billion, not counting the extra capital additions that the existing rig fleet would need to keep operating.

Offshore Rigs

The Baker Hughes, Smith, and Reed rig surveys discussed above all track offshore rigs using the same definitions each uses for onshore rigs. For example, the Hughes Survey reported 122 operating offshore rigs averaged over all weeks in 1997. The 1997

TABLE S-13

CAPITAL COST FOR NEW ONSHORE RIGS UNDER ALTERNATIVE ASSUMPTIONS

	Depth Category 1 < 5k ft.	Depth Category 2 5k–10k ft.	Depth Category 3 10k–15k ft.	Depth Category 4 > 15k ft.	All
Initial Capital Cost (Million $)	$2.20	$5.20	$8.50	$15.00	
Number of New Onshore Rigs					
Base Assumptions	309	808	632	146	1,895
Slower Technology Advancement (0.63% per year improvement)	374	937	747	182	2,240
No Technology (0.00% per year improvement)	445	1,080	876	222	2,623
Slower Attrition (2% per year loss of rigs)	182	564	413	52	1,211
Capital Expenditures for Onshore Rigs (Million 1998$)					
Base Assumptions	680	4,202	5,372	2,190	12,443
Slower Technology Advancement (0.63% per year improvement)	823	4,872	6,350	2,730	14,775
No Technology (0.00% per year improvement)	979	5,616	7,446	3,330	17,371
Slower Attrition (2% per year loss of rigs)	400	2,933	3,511	780	7,624

Reed Rig Census reported 212 active offshore rigs and 237 available rigs. Roughly speaking, the Baker Hughes offshore rig count, which measured just rigs actively "turning to the right," is about 55% of the Reed active count, which picks up rigs that are mobilizing or completing wells.

Another source of data on offshore rigs is Offshore Data Services, Inc. (ODS), which produces the *Gulf of Mexico Rig Locator* and other publications. As shown in Table S-14, that publication tracks on a weekly basis "contracted," "marketed," and "total" offshore rigs. The ODS measure of "contracted rigs" corresponds closely to the Reed "active rig" count. As of September 24, 1999, the offshore fleet contracted in the Gulf of Mexico numbered 207, with 30 of those working in deep water. A total of 284 rigs were being marketed. Additionally 76 rigs (the difference between total rigs and marketed rigs) were not being marketed. The rigs not being marketed are generally "cold stacked" and will require some investment to be brought back to service. Some of the cold stacked rigs may not return to service due to the high costs that would be associated with meeting U.S. Coast Guard certification requirements and classification society standards. Since offshore drilling rigs are mobile, improved market conditions in the Gulf of Mexico could potentially cause rigs to relocate from foreign waters. Conversely, in times of low demand in the United States, offshore rigs are moved to other countries.

Projected Needs for Offshore Rigs

The projected number of offshore wells to be drilled under Reference Case conditions is shown in Figure S-17 by water depth. The recent peak of over 800 wells in 1997 is expected to be reached again after the year 2000 and to be sustained in the late years of the projection. The portion of wells drilled in waters deeper than 1,000 meters grows from 5% in 1997 to 20% in 2010.

Taking into account increasing drilling efficiencies as well as annual attrition rates of 5% for deepwater rigs and 7% for all others, this study projects that 72 additional, unplanned rigs—either reactivations, new construction, or relocations—will be needed by 2015 for the increased offshore activity (Figure S-18). These include 10 deepwater rigs, 32 platform rigs, and 30 jack-up rigs or barges.

TABLE S-14

GULF OF MEXICO RIG INVENTORY

	Total	Marketed	Contracted	Not Marketed
Jack-ups	*139*	*119*	*105*	*20*
Semis	*38*	*34*	*27*	*4*
Drillships	*3*	*3*	*3*	*0*
Submersibles	*7*	*1*	*1*	*6*
Total Mobile	187	157	136	30
Platform	78	57	37	21
Inland Barges	95	70	34	25
All offshore	360	284	207	76

Source: Offshore Data Services, Inc., *Gulf of Mexico Rig Locator*, September 24, 1999.

Figure S-17. Offshore U.S. Well Counts by Water Depth

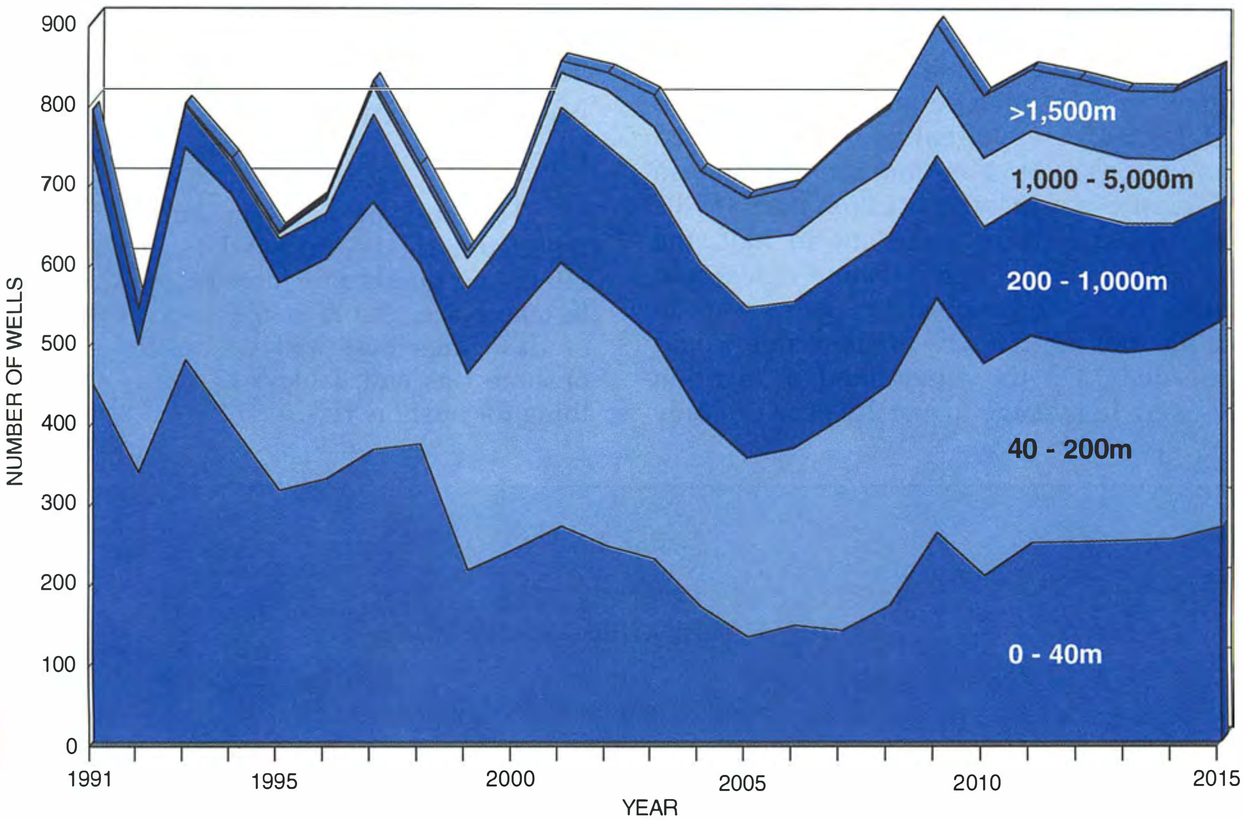
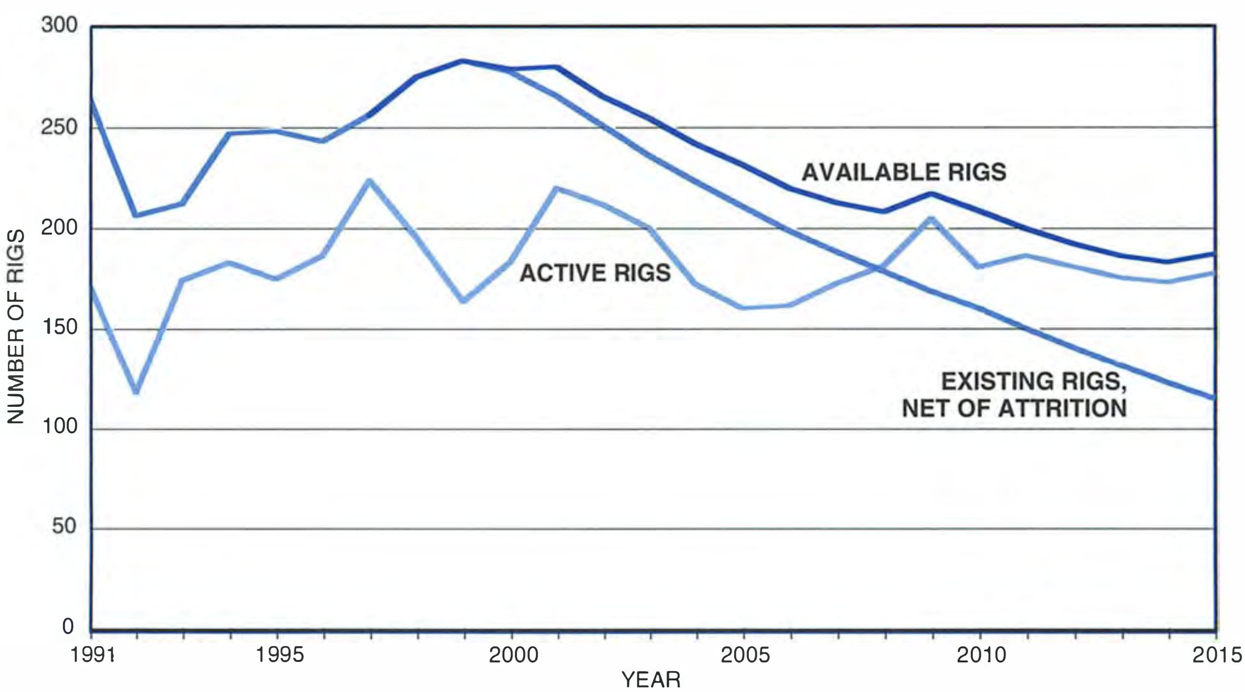


Figure S-18. Offshore Drilling Rig Fleet, 1997–2015



The capital investment for these new rigs is shown in Table S-15. The cost of these new rigs would be about $7.3 billion (1998$) if all new rigs come from new builds. Costs would be lower if some of the rigs currently cold stacked were reactivated or if rigs could be brought in from other countries. Also shown on Table S-15 are alternative estimates based on more conservative assumptions for gains in rig efficiencies and lower attrition rates. If the base efficiency gain were cut in half, the required number of new offshore rigs would increase to 93. If no efficiency gains were to take place at all, 116 new offshore rigs would be needed. On the other hand, if attrition rates were to average to just 2% per year, only 20 new rigs would be needed, although as with onshore rigs, a significant capital investment would be needed to keep the existing rigs operating long into the future.

The Implication of New Rig Construction on Day Rates and Well Costs

The cost of new rig builds must be reflected in rig day rates if the sustained levels of new rig builds anticipated in this study are to take place. Table S-16 shows a calculation of day rates that will be needed for new onshore rigs and Table S-17 shows the same thing for offshore rigs.

TABLE S-15

CAPITAL COST FOR NEW OFFSHORE RIGS UNDER ALTERNATIVE ASSUMPTIONS

	5th Gen. Semi or Drillship 10,000 feet	Jack-up 350 feet	Platform Rigs	All
Initial Capital Cost (Million $)	$325.0	$115.0	$20.00	
Number of New Offshore Rigs				
Base Assumptions	10	30	32	72
Slower Technology Advancement (0.63%–0.75% per year improvement)	16	39	38	93
No Technology (0.00% per year improvement)	23	49	44	116
Slower Attrition (2% per year loss of rigs)	9	–	11	20
Capital Expenditures for Offshore Rigs (Million 1998$)				
Base Assumptions	3,250	3,450	640	7,340
Slower Technology Advancement (0.63%–0.75% per year improvement)	5,200	4,485	760	10,445
No Technology (0.00% per year improvement)	7,475	5,635	880	13,990
Slower Attrition (2% per year loss of rigs)	2,925	–	220	3,145

TABLE S-16

DAY RATE CALCULATIONS FOR NEW ONSHORE RIGS

	Depth Category 1 < 5k feet	Depth Category 2 5k–10k feet	Depth Category 3 10k–15k feet	Depth Category 4 > 15k feet
Rig Description (Horsepower)	500	750	1,500	2,000
Initial Capital Cost (Million $)	$2.20	$5.20	$8.50	$15.00
Day Rate Components ($/Day)				
Non-Fuel Variable Cost	$4,200	$5,000	$5,815	$6,280
Fuel Costs	$195	$293	$585	$780
Total Variable Costs	$4,395	$5,293	$6,400	$7,060
Capital Cost Recovery	$1,240	$2,932	$4,792	$8,457
Total Full Recovery Day Rate	**$5,635**	**$8,224**	**$11,192**	**$15,517**

Capital Cost Recovery Assumptions: Return on Equity, 15.0%; Interest on Debt, 7.5%; Debt:Total Capital Ratio, 0.25; Nominal Rate of Return, 13.1%; Amortization Period (Years), 10; Annual Capital Cost Recovery Factor, 18.5%; New Unit Capacity Utilization, 90%.

The onshore day rates calculated in Table S-16 are much higher than the estimated actual day rates experienced in 1997 (shown earlier in Table S-12 and again in Table S-18). The day rate for the shallowest interval would have to go up 25% while the day rate for the deepest interval would go up 63%. As is shown in Table S-18, these higher day rates would increase onshore well costs by 8% to 20% in each interval assuming the non-rig

TABLE S-17

DAY RATE CALCULATIONS FOR NEW OFFSHORE RIGS

	Jack-up 350 feet	5th Gen. Semi 10,000 feet	Drillship 10,000 feet	Platform Rig
Initial Capital Cost (Million $)	$115.0	$325.0	$325.0	$20.0
Day Rate Components ($/Day)				
Total Variable Costs	$20,000	$50,000	$55,000	$15,000
Capital Cost Recovery	$61,958	$175,098	$175,098	$10,775
Total Full Recovery Day Rate	**$81,958**	**$225,098**	**$230,098**	**$25,775**

Capital Cost Recovery Assumptions: Return on Equity, 15.0%; Interest on Debt, 7.5%; Debt:Total Capital Ratio, 0.40; Nominal Rate of Return, 12.0%; Amortization Period (Years), 10; Annual Capital Cost Recovery Factor, 17.7%; New Unit Capacity Utilization, 90%.

TABLE S-18

IMPLICATIONS OF RIG REPLACEMENT COSTS ON ONSHORE WELL COSTS

	Depth Category 1	Depth Category 2	Depth Category 3	Depth Category 4
	< 5k feet	5k–10k feet	10k–15k feet	> 15k feet
Day Rates ($/Day/Rig)				
1997 Estimated Actual	$ 4,500	$ 5,500	$ 7,000	$ 9,500
Hypothetical Replacement Cost	$ 5,635	$ 8,224	$11,192	$15,517
Dollar per Foot: Estimated 1997				
Rig Cost	$ 15.48	$ 21.25	$ 36.29	$ 67.67
Non-Rig Well Cost	$ 33.97	$ 41.24	$ 70.22	$176.68
Well Cost (JAS)*	$ 49.45	$ 62.49	$106.51	$244.35
Dollar per Foot: Hypothetical at Replacement Cost Day Rate				
Rig Cost	$ 19.38	$ 31.77	$ 58.02	$ 110.53
Non-Rig Well Cost	$ 33.97	$ 41.24	$ 70.22	$ 176.68
Well Cost	$ 53.35	$ 73.01	$ 128.24	$ 287.21
Percentage Change in Replacement Costs vs. 1997				
Rig Cost	25%	50%	60%	63%
Non-Rig Well Cost	0%	0%	0%	0%
Well Cost	8%	17%	20%	18%

*JAS = Joint Association Survey of Drilling Costs.

costs stayed at their 1997 level, a relatively high-cost year for all oilfield services. Although the model projections take the rig replacement cost calculations into account, their impact on projected well costs is less than shown in Table S-18 because the assumed increases in rig efficiency mute the effect of higher day rates.

The implications of rig replacement economics for offshore drilling are more severe because rig costs tend to be a higher portion of the cost of a well—about half versus 25-30% for the onshore. For example, in 1997 the day rates for jack-up rigs averaged approximately $46,000 per day, versus the $82,000 day rate needed to justify new rig construction. This would imply that well costs on the shelf would have to go up almost 40% [(82,000 – 46,000) ÷ 46,000 x 50%] over 1997 levels to provide adequate day rates to justify building new rigs.

Chapter Four

Investment in Research and Development Will Be Needed to Maintain the Pace of Advancements in Technology

Technology advancement has played a major role in the increase of the North American resource base by:

- Improving efficiency of drilling, equipment, operating, and other costs
- Increasing recovery factors of discovered oil and gas in place
- Improving success rates (i.e., reducing the number of dry holes)
- Revealing new areas and types of resources for exploitation through innovative geologic and engineering concepts.

Information Technology has made possible dramatic advances in 3D seismic, directional drilling, and completion techniques. The persistent improvement of computing power at consistently decreasing prices has placed increasingly powerful Information Technology tools in the hands of even the smallest producers, improving efficiency, and reducing cost structures. Growing processing power is allowing applications to be moved from mainframes to high-efficiency workstations. The advent of object-based and improved data storage technologies have allowed greater access to information in highly user-friendly interfaces. Connectivity has been enhanced by use of high-capacity networks, fiber optic and satellite communication links, and the Internet (intranets, extranets, etc.).

Advances in technology do not happen in a vacuum. All industry stakeholders will have to support continued investment in technology research and development—from the producer who must apply the newest tools/techniques to the next opportunity, to the investor who must at times be willing to sacrifice immediate gains for longer-term growth. Continued and increased funding of research and development is required for the North American resource base to live up to its potential. Cooperative measures by all parties will be required. If the proper proactive measures are taken, the following items could have a significant impact on future gas production:

- **4D Seismic.** 4D seismic combines the fourth dimension of time with the 3D model to locate and monitor the movement of fluids in the reservoir. Visualization centers project these images onto screens and allow scientists to "see" such events as the enlargement of a gas cap during oil production or the shrinkage of the cap during gas production.
- **Real-Time Reservoir Modeling.** The real-time reservoir model uses the 4D seismic measurements described above to allow quick updating as new data are produced and enables drilling and field development decisions to be made quickly.

- **Deep Wireline Measurements.** Deep measurements of gravity and electromagnetic forces provide information that complements the seismic data. Wireline-based deep measurements typically have higher resolution than seismic and can provide enhanced detail about gas location and movement.
- **Integrated Well Planning.** Well planning is the process of effectively and accurately planning for optimum wellbore placement in the reservoir, determination of suitable equipment/systems for completion and production, and maximizing reservoir output and economics.
- **Drilling Systems.** A major focus on drilling capabilities will continue as drilling time is a major component of rig cost and thus the total cost of the well. Significant strides have been made in the last several years with regard to rates of penetration, equipment dependability, downhole data gathering, and drilling dynamics. The ability to steer and extend the wellbore both vertically and horizontally to zones of interest has increased significantly with the advent of extended reach wells, horizontal drilling, and multi-laterals.

The 1999 Study presumes that the foregoing technology advances and others will continue to expand, causing increased exploratory success and optimized well production capability. Should this advancement not occur, or should these technologies prove less valuable to producers than expected, the 1999 Study's projections of growth in North American natural gas productive capacity growth may be optimistic.

The technology drivers set in the Hydrocarbon Supply Model for the 1999 Study and two alternative cases are shown in Table S-19. (For additional discussion regarding the

TABLE S-19

TECHNOLOGY DRIVERS SET IN HYDROCARBON SUPPLY MODEL (Percentage of Annual Improvements)

	Slower Technology Advancement Case	**Reference Case**	**Faster Technology Advancement Case**
New Field Exploration Efficiency	Low Permeability		
2000	0.75%	1.5%	2.5%
2010	0.90%	1.8%	2.8%
2015	1.10%	2.2%	3.2%
Platform Cost Reduction	0.75%	1.5%	4.0%
Drilling and Completion Cost Reduction			
Onshore & Shelf	1.25%	2.5%	3.0%
Deepwater	1.50%	3.0%	3.5%
Improvement in Estimated Ultimate Recovery per Well			
Conventional	0.5%	1.0%	1.5%
	1.05%	2.1%	2.5%
Nonconventional	0.75-1.50%	1.5-3.0%	1.5-3.0%

Figure S-19. Technology Sensitivities – Production Differences

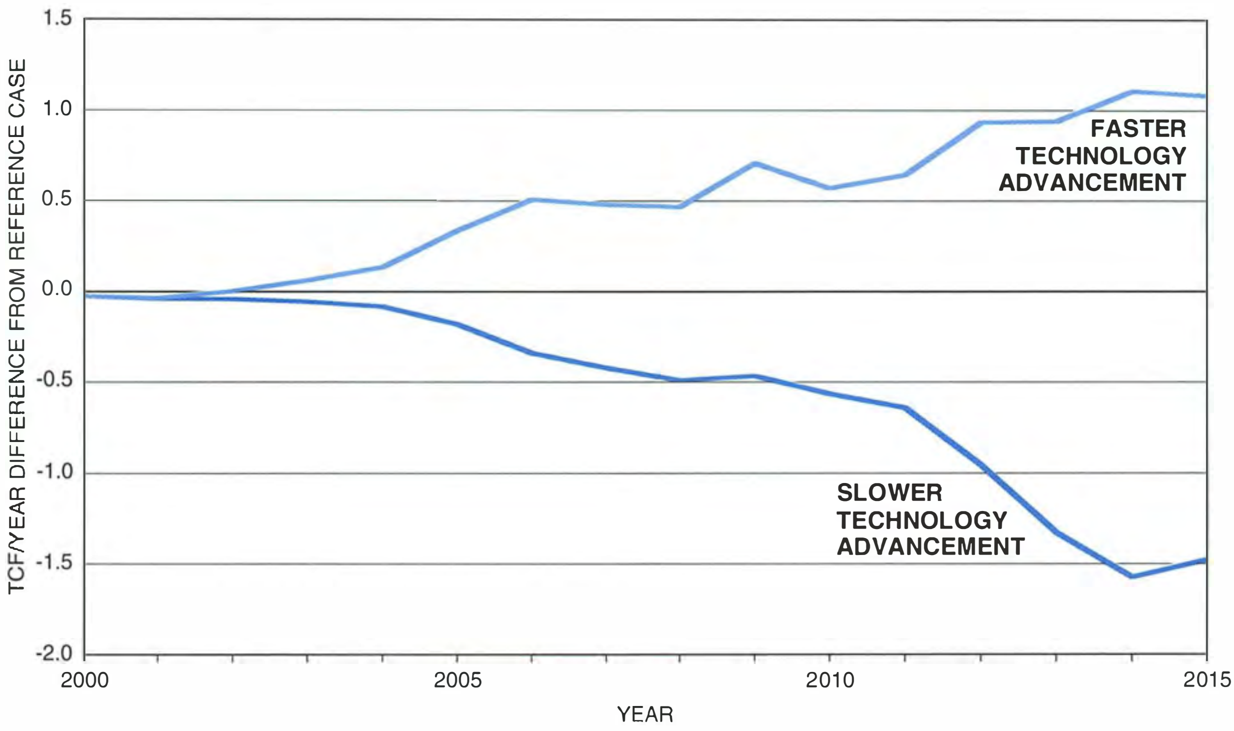
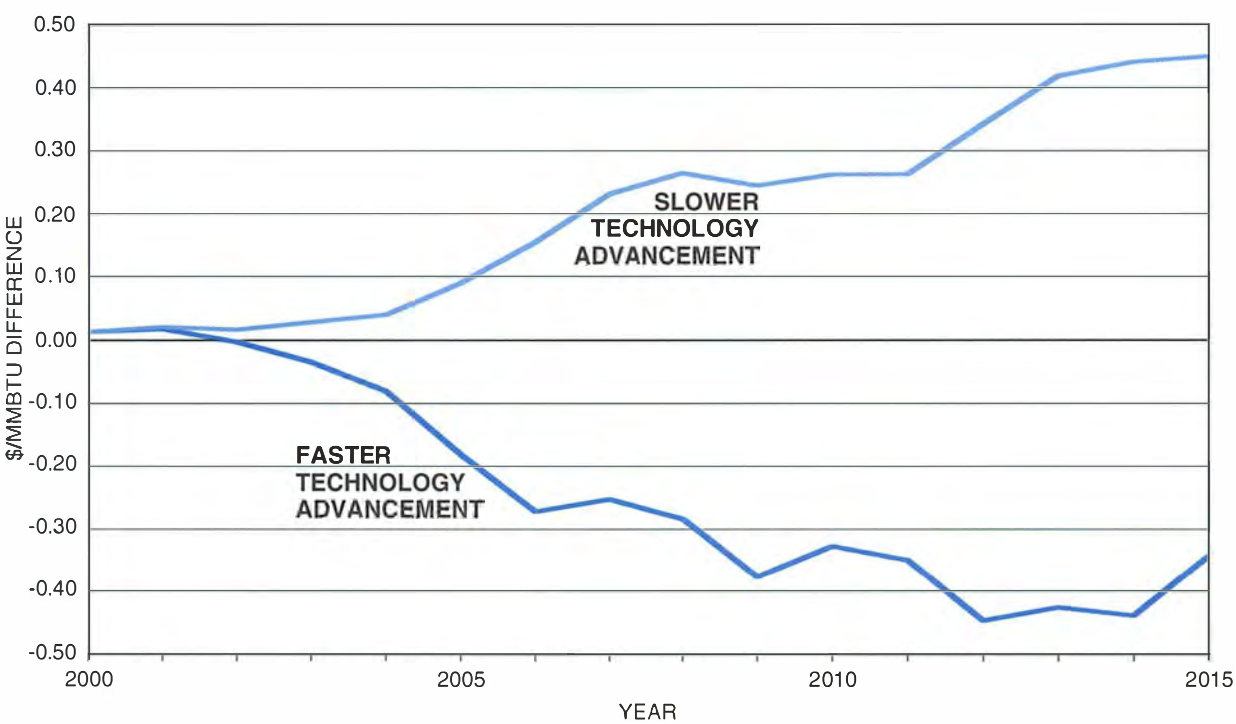


Figure S-20. Technology Impact on Projected Henry Hub Prices



Technology Drivers, please see Chapter Seven of this Supply Task Group Report.) The 1999 Study represents the study group's view of what can be expected for technological advances based on recent levels of R&D funding and the general effectiveness of those efforts. The Faster Technology Advancement case assumes either a higher level of funding or a greater-than-expected number of significant technological breakthroughs. The Slower Technology Advancement case envisages a decline in R&D funding with a resulting halving of each Reference Case technological driver in the model. The results of the sensitivity cases are shown in Figure S-19.

As Figure S-19 illustrates, the Faster Technology Advancement case assumptions result in total U.S. gas production being approximately 1 TCF high in 2015 versus the Reference Case. Conversely, the Slower Technology Advancement case assumptions result in 1.5 TCF lower gas production in the same time period.

As is illustrated in Figure S-20, more favorable advances in technology have the potential of lowering gas prices by $0.40 per MMBtu by 2015. Conversely, the more pessimistic scenario has an almost opposite effect.

Conclusion: Increased investment in Technology Research and Development is imperative. If adequate funding is not maintained, it could result in substantially lower production and higher gas prices for the consumer.

Chapter Five

Sensitivity Analyses

This chapter presents the results of ten sensitivity cases. Results are presented as a difference in supply or price from the Reference Case. The resource base, oil price, and GDP growth sensitivities are described here. The access sensitivities are described in Chapter Two and the technology sensitivities are described in Chapter Four.

Resource Base Sensitivity Cases

The Supply Task Group decided to use a nominal range of +/- 250 TCF for the resource base sensitivities. This 250 TCF represents the difference from the base assumptions on a current technology basis. On the basis of the advanced technology well recoveries that were adopted for the study's Reference Case, the divergence is 274 TCF in the Larger Resource Base sensitivity and 301 TCF in the Smaller Resource Base sensitivity, as shown in Table S-20. In comparison to the Reference Case U.S. and Canadian Assessed Additional Resource volume of 1,912 TCF, these volumes represent a range of about +/- 15%. Tables S-21 and S-22 present the regional distribution of the resource base changes that were made. For a map of HSM supply regions, see Figure S-1 in Chapter One of this Supply Task Group Report.

Larger Resource Base Sensitivity

A Larger Resource Base sensitivity was developed to model the effects of a more optimistic view of the remaining North American gas resource base. Gas resources were added to regions and depth intervals believed to have significant upside potential relative to the Reference Case. Decisions were based upon the results of industry discussions and comparisons with the assessments of other organizations, such as the U.S. Geological Survey, U.S. Minerals Management Service, Potential Gas Committee, and various Canadian organizations.

OLD FIELD RESERVE APPRECIATION

Old Field Reserve Appreciation was increased to 370 TCF in the lower-48 states and 26 TCF in Canada. These changes represent an increase of 15% for all onshore regions (with the exception of South Louisiana, for which additional appreciation resources were added). For the Central & Western Gulf of Mexico, 20 TCF of reserve appreciation was added to represent previously unassessed deep resources in existing shelf fields. This resource base represents the development of reservoirs below 15,000 feet in large, older fields. These reservoirs have not been extensively developed, due to low permeability, higher costs, industry focus on shallow zones, and the deepwater play. Advances in seismic imaging, directional drilling, and stimulation may result in development of this resource during the projection period.

TABLE S-20

SUMMARY OF GAS RESOURCE BASE CHANGES FOR LARGER AND SMALLER RESOURCE BASE SENSITIVITY CASES*

		Larger Resource Base		Smaller Resource Base	
	Reference Case (TCF)	Change (TCF)	Change (%)	Change (TCF)	Change (%)
Lower-48	1,309	+207	+16%	-215	-16%
Canada	603	+67	+11%	-86	-14%
Total	**1,912**	**+274**	**+14%**	**-301**	**-16%**

*Trillion Cubic Feet of Assessed Additional Resources (Old Field Reserve Appreciation, New Fields, and Nonconventional)

NEW FIELDS

New fields were increased to 758 TCF in the lower-48 states and 432 TCF in Canada. In the Central & Western Gulf of Mexico, a Larger Resource Base case was developed to represent a more aggressive view of deepwater potential. This assessment increased the new field resource base for the region by 44 TCF, to 250 TCF. The Reference Case assessment of new field potential for the deepwater is 140 TCF, and the sensitivity case has a resource base of approximately 184 TCF. All of the increase is in water depths greater than 1,000 meters. (There is no increase in the 200–1,000 meter interval). New field potential was also increased in Appalachia, the onshore Gulf Coast, the Mid-Continent, and the Permian Basin. Resources in these areas were added to depth intervals below 10,000 feet.

In Canada, new field potential was increased in the western provinces, primarily to reflect additional potential in the Disturbed Belt of Alberta and British Columbia. In the East Coast offshore region, 11 TCF of new field potential was added to represent deepwater areas of offshore Nova Scotia. The Reference Case assessment of that subregion represents shelf resources only.

COALBED METHANE

Coalbed methane resources were added in several regions for the Larger Resource Base case. The coalbed resource was increased a total of 16 TCF in the lower-48 states and 15 TCF in Canada. Coalbed methane is rapidly emerging in North America, and extensive coalbed deposits exist in areas believed to have good potential, but which are not included in the Reference Case. In the lower-48 states, resources were added to the Rocky Mountain Foreland Region to reflect additional potential in the Uinta Basin and other basins. A coalbed methane resource was added to the Western Overthrust Belt, on the basis of a Potential Gas Committee assessment and confirmation by Supply Task Group members. In the Mid-Continent, coalbed methane resources were added to represent potential in the Anadarko Basin of Oklahoma.

In Canada, there are several areas of known coalbed methane potential that are not included in the Reference Case. Approximately 9 TCF of coalbed methane resources were added to British Columbia, to represent a large amount of gas-in-place in the northeastern portion of that province. In addition, 6 TCF of coalbed methane resources were added to the onshore area of Eastern Canada to represent known deposits that have yet to become productive, but may be developed when new pipeline transportation becomes available.

Smaller Resource Base Sensitivity

A Smaller Resource Base sensitivity was developed to represent a pessimistic view of

TABLE S-21

LARGER RESOURCE BASE SENSITIVITY
CHANGE IN RESOURCE BASE RELATIVE TO BASE CASE
CURRENT TECHNOLOGY RECOVERABLE
(Billion Cubic Feet)

		Old Field Appreciation			New Fields			Coalbed Methane			Shale			Tight Gas			
	Model Region	**Ref. Case**	**Change**	**High Case**	**Ref. Case**	**Change**	**High Case**	**Ref. Case**	**Change**	**High Case**	**Ref. Case**	**Change**	**High Case**	**Ref. Case**	**Change**	**High Case**	**Total Change**
1	A: Appalachia	2,301	345	2,646	24,968	7,100	32,068	14,717		14,717	17,683		17,683	13,398		13,398	7,445
2	B: Eastern Gulf Onshore	5,069	760	5,829	7,806	3,400	11,206	4,651		4,651							4,160
3	C: North Central	2,718	408	3,126	8,815		8,815	1,908		1,908	15,327		15,327				408
4	D: Arkla - East Texas	25,864	3,880	29,744	19,716	5,700	25,416				5,779		5,779	23,577		23,577	9,580
5	E: South Louisiana	20,361	13,000	33,361	10,654	13,100	23,754										26,100
6	G: Texas Gulf Onshore	54,341	8,151	62,492	47,732	8,200	55,932							8,336		8,336	16,351
7	WL: Williston Basin	2,653	398	3,051	2,723		2,723										398
8	FR: Rocky Mountain, Foreland	28,949	4,342	33,291	88,528		88,528	19,934	4,300	24,234				104,806		104,806	8,642
9	SJB: San Juan Basin	11,673	1,751	13,424	1,884		1,884	8,593		8,593							1,751
10	OV: Overthrust Belt	702	105	807	6,160		6,160		2,500	2,500							2,605
11	JN: Mid-Continent	48,430	7,265	55,695	35,447	25,900	61,347	5,732	5,800	11,532				12,788		12,788	38,965
12	JS: Permian Basin	22,319	3,348	25,667	28,074	9,000	37,074							14,677		14,677	12,348
13	L: West Coast Onshore	5,717	858	6,575	18,371		18,371										858
14	BO: Eastern Gulf of Mexico	2,160	324	2,484	36,723		36,723										324
15	EGO: Cent. & West. Gulf of Mexico	70,661	20,000	90,661	188,373	40,800	229,173										60,800
16	LO: West Coast Offshore	1,039	156	1,195	18,900		18,900										156
17	AO: Atlantic Offshore	0	0	0	27,800		27,800										0
	Lower-48 Total	**304,957**	**65,090**	**370,047**	**572,674**	**113,200**	**685,874**	**55,535**	**12,600**	**68,135**	**38,789**	**0**	**38,789**	**177,582**	**0**	**177,582**	**190,890**
20	ASM: Alberta, Sas., Man.	18,620	2,793	21,413	56,348	19,400	75,748	59,184		59,184				65,023		65,023	22,193
21	BC: British Columbia	3,283	492	3,775	29,195	14,400	43,595		7,500	7,500							22,392
22	NWC: Northwest Canada	0	0	0	72,876		72,876										0
23	EC: Eastern Canada	478	72	550	86,905	10,000	96,905		5,000	5,000							15,072
24	ART: Arctic Canada	0	0	0	100,867		100,867										0
	Canada Total	**22,381**	**3,357**	**25,738**	**346,191**	**43,800**	**389,991**	**59,184**	**12,500**	**71,684**	**0**	**0**	**0**	**65,023**	**0**	**65,023**	**59,657**
	North America Totals	**327,338**	**68,447**	**395,785**	**918,865**	**157,000**	**1,075,865**	**114,719**	**25,100**	**139,819**	**38,789**	**0**	**38,789**	**242,605**	**0**	**242,605**	**250,547**

TABLE S-22

SMALLER RESOURCE BASE SENSITIVITY
CHANGE IN RESOURCE BASE RELATIVE TO REFERENCE CASE
ADVANCED TECHNOLOGY RECOVERABLE
(Billion Cubic Feet)

		Old Field Appreciation			New Fields			Coalbed Methane			Shale Gas			Tight Gas			
	Model Region	**Reference Case**	**Change**	**Low Case**	**Reference Case**	**Change**	**Low Case**	**Reference Case**	**Change**	**Low Case**	**Reference Case**	**Change**	**Low Case**	**Reference Case**	**Change**	**Low Case**	**Total Change**
1	A: Appalachia	2,301	-575	1,726	27,772	-6,012	21,760	19,433	-9,643	9,790	23,389	-11,769	11,620	18,266	-9,137	9,129	-37,136
2	B: Eastern Gulf Onshore	5,069	-1,267	3,802	8,674	0	8,674	5,209	0	5,209		0			0		-1,267
3	C: North Central	2,718	-679	2,039	9,796	0	9,796	2,518	0	2,518	21,950	-8,594	13,356		0		-9,273
4	D: Arkla - East Texas	25,864	-6,466	19,398	22,196	0	22,196		0		7,207	0	7,207	29,816	-14,918	14,898	-21,384
5	E: South Louisiana	20,361	-5,090	15,271	11,838	0	11,838		0			0			0		-5,090
6	G: Texas Gulf Onshore	54,341	-13,585	40,756	52,550	0	52,550		0			0		9,114	0	9,114	-13,585
7	WL: Williston Basin	2,653	-663	1,990	3,088	0	3,088		0			0			0		-663
8	FR: Rocky Mtn. Foreland	28,949	-7,237	21,712	99,180	0	99,180	29,371	0	29,371		0		136,972	-68,477	68,495	-75,714
9	SJB: San Juan Basin	11,673	-2,918	8,755	2,209	0	2,209	10,058	0	10,058		0			0		-2,918
10	OV: Overthrust Belt	702	-175	527	6,731	0	6,731		0			0			0		-175
11	JN: Mid-Continent	48,430	-12,107	36,323	39,675	0	39,675	7,449	0	7,449		0		16,923	0	16,923	-12,107
12	JS: Permian Basin	22,319	-5,580	16,739	31,353	0	31,353		0			0		19,521	0	19,521	-5,580
13	L: West Coast Onshore	5,717	-1,429	4,288	20,205	-9,897	10,308		0			0			0		-11,326
14	BO: Eastern Gulf of Mexico	2,160	-540	1,620	40,655	0	40,655		0			0			0		-540
15	EGO: Cent. & West. Gulf of Mex.	70,661	-17,665	52,996	205,328	0	205,328		0			0			0		-17,665
16	LO: West Coast Offshore	1,039	-260	779	20,790	0	20,790		0			0			0		-260
17	AO: Atlantic Offshore	0	0	0	30,580	0	30,580		0			0			0		0
	Lower-48 Total	**304,957**	**-76,236**	**228,721**	**632,620**	**-15,909**	**616,711**	**74,038**	**-9,643**	**64,395**	**52,546**	**-20,363**	**32,183**	**230,612**	**-92,532**	**138,080**	**-214,683**
20	ASM: Alberta, Sas., Man.	18,620	-4,655	13,965	62,548	0	62,548	74,007	-37,027	36,980		0		86,827	-43,409	43,418	-85,091
21	BC: British Columbia	3,283	-821	2,462	32,465	0	32,465					0			0		-821
22	NWC: Northwest Canada	0	0	0	80,972	0	80,972					0			0		0
23	EC: Eastern Canada	478	-119	359	96,497	0	96,497					0			0		-119
24	ART: Arctic Canada	0	0	0	111,051	0	111,051					0			0		0
	Canada Total	**22,381**	**-5,595**	**16,786**	**383,533**	**0**	**383,533**	**74,007**	**-37,027**	**36,980**	**0**	**0**	**0**	**86,827**	**-43,409**	**43,418**	**-86,031**
	North America Totals	**327,338**	**-81,831**	**245,507**	**1,016,153**	**-15,909**	**1,000,244**	**148,045**	**-46,670**	**101,375**	**52,546**	**-20,363**	**32,183**	**317,439**	**-135,941**	**181,498**	**-300,714**

remaining North American gas resources. Resources were reduced in all categories of undiscovered and undeveloped resources. As with the Larger Resource Base case, adjustments were based upon Supply Task Group discussions and comparisons with the assessments of other organizations. Table S-22 shows the regional distribution of resource base changes made for the Smaller Resource Base sensitivity. The total reduction was 301 TCF.

OLD FIELD RESERVE APPRECIATION

Total gas reserve appreciation potential in the lower-48 states and Canada was reduced by 25% relative to the Reference Case. This results in a reserve appreciation volume of 229 TCF for the lower-48 states and 17 TCF for Canada.

NEW FIELDS

New field potential in the Smaller Resource Base sensitivity was reduced by 16 TCF in the lower-48 states and was unchanged for Canada. Conventional new field resources of Appalachia and the West Coast Onshore were reduced on the basis of industry discussions and comparison with other assessments.

COALBED METHANE

Coalbed methane potential was reduced by a total of 10 TCF in the lower-48 states and 37 TCF in Canada. The reduction in Appalachian resources of 10 TCF (50%) reflects a lack of significant activity in that region outside of southwestern Virginia. The reduction in Western Canada of 37 TCF (50%) reflects the uncertainty of the assessment of that resource. The coalbeds of Alberta are known to contain vast quantities of gas at moderate depths, but development of this resource remains in the very early stages.

SHALE GAS

The shale gas resource base was reduced a total of 20 TCF. Appalachian Devonian Shale was reduced by 12 TCF or 50% to reflect downside uncertainty. The Devonian Shale contains many potential well sites, but activity has declined. In the North Central region, the resource potential of the Devonian Antrim Shale was reduced by 3 TCF to reflect the uncertainty that the southern flank of the Michigan Basin will become economic. Shale resources in the Illinois Basin and Cinncinnati Arch areas were removed from the model (a 5 TCF reduction), because their economic viability is uncertain.

TIGHT GAS

The tight gas resource base was reduced by a total of 93 TCF in the lower-48 states and 43 TCF in Canada. In the lower-48 states, tight gas resources were reduced by 50% in Appalachia, Arkla-East Texas, and the Rockies. In Western Canada, tight gas resources in the Western Canadian Sedimentary Basin were also reduced by 50% to reflect uncertainty in the resource assessment.

Results of Resource Base Sensitivities

Table S-23 and Figure S-21 present the results of all ten sensitivities that were evaluated in the 1999 Study. The results of the Reference Case are shown in the first row of the table. The Larger and Smaller Resource Base sensitivities are shown to have the greatest impact on gas production and wellhead prices of any of the sensitivities. For example, in the Larger Resource Base sensitivity, lower-48 gas production in 2010 is 1.55 TCF higher than the Reference Case. Canadian production in this case is 0.48 TCF higher in 2010. Henry Hub natural gas prices (1998$) are $0.96 per MMBtu lower in the Larger Resource Base sensitivity and $0.56 per MMBtu higher in the Smaller Resource Base sensitivity in 2010.

Oil Price Sensitivity Cases

Higher Oil Price Sensitivity

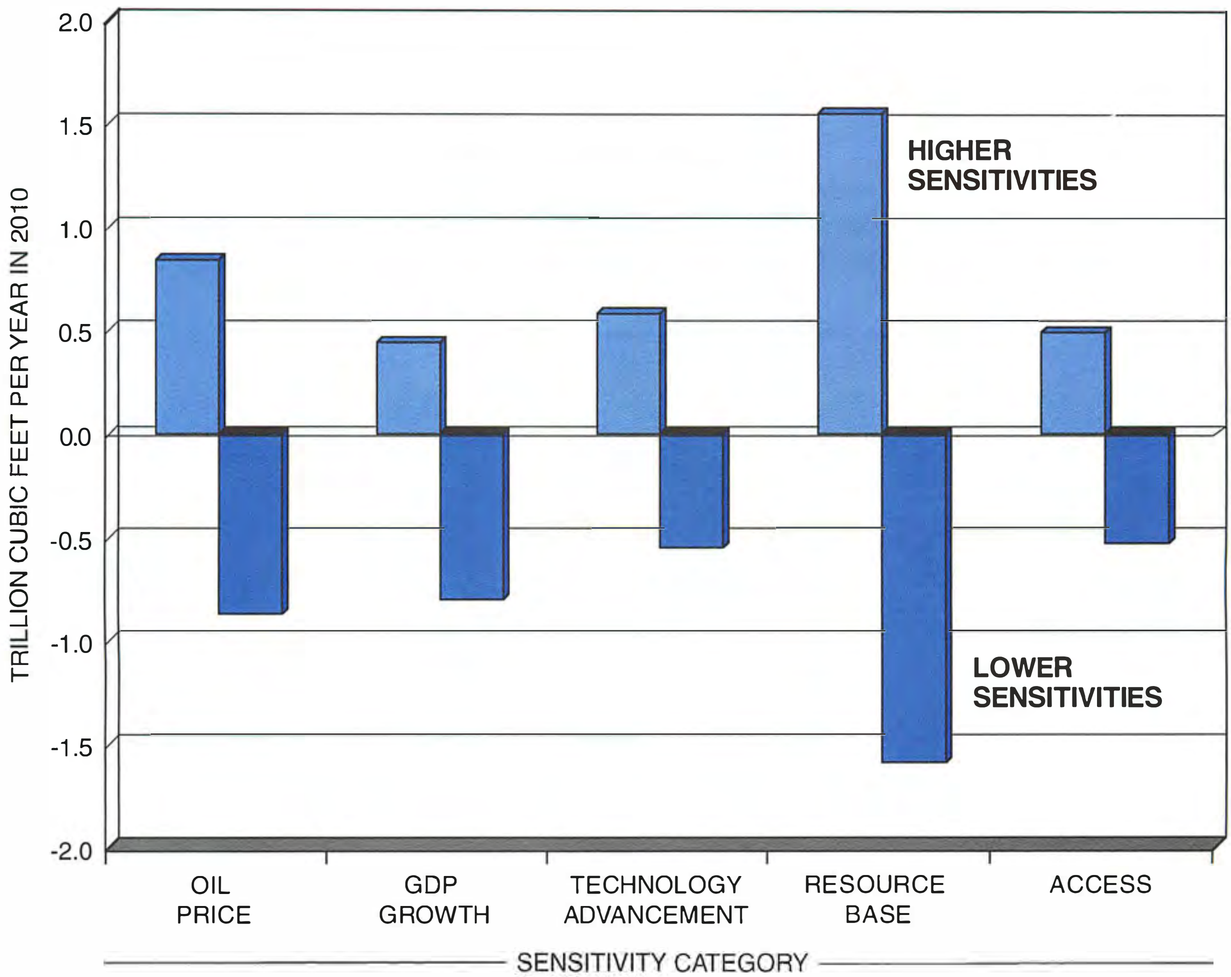
Two oil price sensitivities were developed. A Higher Oil Price sensitivity was developed to model the effects of higher than anticipated crude oil prices. In the Reference Case, the assumption is made that oil prices average $18.50 in constant dollars throughout the projection. In the Higher Oil Price case, prices average $22.00 throughout, an increase of $3.50 or 19%. (These prices represent the price of West Texas Intermediate; the corresponding Refiner Acquisition Cost of Crude

TABLE S-23

SUMMARY OF SENSITIVITY CASE RESULTS

	U.S. Production (TCF per year)		Lower-48 Production (TCF per year)		Canada Production (TCF per year)		U.S. Consumption (TCF per year)		Henry Hub Gas Prices (1998$ per MMBtu)	
	2010	**2015**	**2010**	**2015**	**2010**	**2015**	**2010**	**2015**	**2010**	**2015**
Reference Case	**25.05**	**26.50**	**24.64**	**26.07**	**7.40**	**8.17**	**29.47**	**31.84**	**3.23**	**3.81**
Higher Oil Price	25.90	28.33	25.48	27.85	7.30	8.46	30.16	33.82	3.41	3.83
Lower Oil Price	24.15	24.91	23.77	24.51	7.23	7.85	28.46	29.97	2.96	3.51
Higher GDP Growth	25.53	27.40	25.08	26.92	7.68	8.44	30.07	32.69	3.58	4.15
Lower GDP Growth	24.27	25.58	23.84	25.14	7.17	7.87	28.55	30.77	2.92	3.43
Faster Technology Advancement	25.62	27.59	25.22	27.13	7.61	8.30	30.21	32.97	2.91	3.47
Slower Technology Advancement	24.49	25.03	24.09	24.61	7.19	8.03	28.75	30.19	3.50	4.26
Larger Resource Base	26.57	28.26	26.19	27.87	7.88	8.42	31.35	33.75	2.27	3.15
Smaller Resource Base	23.48	24.68	23.05	24.22	7.44	7.63	27.96	29.52	3.79	4.47
Increased Access	25.55	28.05	25.13	27.62	7.35	8.12	29.90	33.29	3.02	3.36
Reduced Access	24.53	26.28	24.11	25.84	7.55	8.20	29.06	31.62	3.39	3.89
Difference from Reference Case (amount)										
Higher Oil Price	0.85	1.83	0.84	1.78	-0.10	0.29	0.69	1.98	0.18	0.02
Lower Oil Price	-0.90	-1.59	-0.87	-1.56	-0.17	-0.32	-1.01	-1.87	-0.27	-0.30
Higher GDP Growth	0.48	0.90	0.44	0.85	0.28	0.27	0.60	0.85	0.35	0.34
Lower GDP Growth	-0.78	-0.92	-0.80	-0.93	-0.23	-0.30	-0.92	-1.07	-0.31	-0.38
Faster Technology Advancement	0.57	1.09	0.58	1.06	0.21	0.13	0.74	1.13	-0.32	-0.34
Slower Technology Advancement	-0.56	-1.47	-0.55	-1.46	-0.21	-0.14	-0.72	-1.65	0.27	0.45
Larger Resource Base	1.52	1.76	1.55	1.80	0.48	0.25	1.88	1.91	-0.96	-0.66
Smaller Resource Base	-1.57	-1.82	-1.59	-1.85	0.04	-0.54	-1.51	-2.32	0.56	0.66
Increased Access	0.50	1.55	0.49	1.55	-0.05	-0.05	0.43	1.45	-0.21	-0.45
Reduced Access	-0.52	-0.22	-0.53	-0.23	0.15	0.03	-0.41	-0.22	0.16	0.08
Difference from Reference Case (percentage)										
Higher Oil Price	3%	7%	3%	7%	-1%	4%	2%	6%	6%	1%
Lower Oil Price	-4%	-6%	-4%	-6%	-2%	-4%	-3%	-6%	-8%	-8%
Higher GDP Growth	2%	3%	2%	3%	4%	3%	2%	3%	11%	9%
Lower GDP Growth	-3%	-3%	-3%	-4%	-3%	-4%	-3%	-3%	-10%	-10%
Faster Technology Advancement	2%	4%	2%	4%	3%	2%	3%	4%	-10%	-9%
Slower Technology Advancement	-2%	-6%	-2%	-6%	-3%	-2%	-2%	-5%	8%	12%
Larger Resource Base	6%	7%	6%	7%	6%	3%	6%	6%	-30%	-17%
Smaller Resource Base	-6%	-7%	-6%	-7%	1%	-7%	-5%	-7%	17%	17%
Increased Access	2%	6%	2%	6%	-1%	-1%	1%	5%	-7%	-12%
Reduced Access	-2%	-1%	-2%	-1%	2%	0%	-1%	-1%	5%	2%

Figure S-21. Impact of NPC Sensitivity Cases On Lower-48 Gas Production Relative to Reference Case - 2010



would be approximately $16.60. Refiner Acquisition Cost of Crude is a volume-weighted price measure of all crude oils consumed by U.S. refiners.)

Lower Oil Price Sensitivity

A Lower Oil Price sensitivity was developed to model the effects of lower than anticipated crude oil prices. In this case, West Texas Intermediate prices are assumed to average $15.00 per barrel, or $3.50 per barrel less than in the Reference Case.

Results of Oil Price Sensitivities

Table S-23 shows the results of the oil price sensitivities. In the Higher Oil Price case, lower-48 gas production in 2010 increases by 0.84 TCF, and Henry Hub natural gas prices increase by $0.18 per MMBtu, while in the Lower Oil Price case, production declines by 0.87 TCF and Henry Hub natural gas prices decline by $0.27 per MMBtu.

GDP Growth Sensitivity Cases

Higher GDP Growth Sensitivity

Two GDP growth sensitivities were developed. In the Reference Case, the U.S. Gross Domestic Product (GDP) is projected to grow at an average rate of 2.5% per year and the Canadian GDP is projected to grow at a rate of 2.2% per year. In the Higher GDP Growth sensitivity, the average GDP is 0.5% per year higher.

Lower GDP Growth Sensitivity

A Lower GDP Growth sensitivity was developed in which the average GDP growth is 0.5% lower than in the Reference Case.

Results of GDP Growth Sensitivities

Table S-23 shows the results of the GDP growth sensitivities. In the Higher GDP Growth case, U.S. natural gas consumption increases from 29.47 TCF in 2010 in the Reference Case to 30.07 TCF, an increase of 600 BCF per year. In the Lower GDP Growth case, U.S. natural gas consumption in 2010 declines to 28.55 TCF or 920 BCF per year. Lower-48 gas production in 2010 increases from 24.64 TCF in the Reference Case to 25.08 TCF in the Higher GDP Growth case, and declines to 23.84 TCF in the Lower GDP Growth case. Henry Hub natural gas prices in 2010 increase by \$0.35 per MMBtu in the Higher GDP Growth case and decline by \$0.31 per MMBtu in the Lower GDP Growth case.

Chapter Six

Major Resource Area Discussions

Gulf of Mexico

The Gulf of Mexico (GOM) has been and will continue to be one of the key regions for supplying natural gas for the United States. The GOM, as of 1-1-1998, has produced 143 TCF of natural gas and has existing proved gas reserves of 33 TCF. Assessed Additional Resources for the GOM are 319 TCF or 24% of the lower-48 resource.

The history of the GOM has been a continuous exploration and production migration from near shore, shallow water to deeper waters. The split on cumulative GOM gas production has been 97% from the shelf (water depths less than 200 meters) and 3% from the deepwater (water depths greater than 200 meters). However, the forecast shows this trend changing with large increases in deepwater production and a gradual decline in shelf production.

The majority of development activity and production response from the GOM in the last ten years has been in the shelf and was fueled by the application of 3D seismic technology along with technology advances in directional drilling and completion practices. During this period, the exploration activity in the deepwater GOM increased dramatically, resulting in many discoveries and a growing inventory of development prospects.

The deepwater forecast for gas production in the Reference Case shows an increase from 1.5 TCF in 2000 to 4.5 TCF in 2010 and 4.6 TCF in 2015. Due to the maturity of the shelf, production from that area during the forecast period will decrease. The net will be an overall GOM natural gas production increase from 5.7 TCF in 2000 to 8.0 TCF in 2010 followed by a slight decrease to 7.6 TCF in 2015. Relative gas production contributions for 2015 are forecast to be 39% for the shelf and 61% for the deepwater GOM.

Most of the GOM unproved gas reserves are associated with New Field exploration in the deeper waters. A volume of 139 TCF is estimated for the deepwater areas in Central & Western GOM. The unproved gas reserves associated with field appreciation are significant at 73 TCF with the majority of this being in the shelf.

Key pieces for the GOM in the HSM were the Reserve Appreciation model for the shelf, the field size distribution for New Fields, and the associated development schemes and costs for deepwater. The model incorporates technology advances in deepwater GOM that result in a steady decrease in exploration and development costs.

The subsalt play in the GOM has a great deal of potential. However, the impact of subsalt development on GOM production in the model has been tempered to reflect the timing of necessary technology advances to improve finding success and reduce drilling costs.

The Eastern GOM existing production area and the MMS Lease Sale 181 area have been incorporated into the model forecast with leasing for the Sale 181 area to start in 2001.

Figures S-22, S-23, and S-24 show the production and resource estimates for the GOM and the lower-48 states.

Gulf of Mexico Subcategories

For purposes of grouping areas to estimate total original hydrocarbon field distributions and development costs, the Central & Western GOM was split into the following categories: water depths of 0-40m, 40-200m, 200-1,000m, 1,000-1,500m and 1,500m+ (as shown in Figure S-25), and subsalt. Original in-place hydrocarbon field distributions and development cost models were developed for each category.

The Eastern GOM was split up into eight categories, again for purposes of grouping areas to estimate hydrocarbon field distributions, development costs, and access timing.

Resource Base

Proved reserves of natural gas in the GOM as of 1-1-98 were 33 TCF. Assessed Additional Resources total 319 TCF. Table S-24 presents the assessment of gas resources for the Eastern and the Central & Western GOM regions. The split between New Field and Old Field Appreciation resources is shown in Figures S-26 and S-27.

The New Field resource base was estimated by assuming an original in-place hydrocarbon field distribution and subtracting the discovered fields. Differences in the total field numbers and hydrocarbon volumes exist among the various categories due to sedimentary volume estimates and the assumed hydrocarbon yields. The gas-in-place is calculated by applying the gas/oil ratio assumptions, which vary from 74% gas and 26% oil in the shelf to 34% gas and 66% oil in some of the deepwater GOM areas. A comparison of the hydrocarbon yields per cubic mile is shown for each category along with the assumptions for gas/oil ratio in Table S-25.

The Old Field Reserve Appreciation estimates were based on historical trends of GOM field reserve growth and historical trends of ultimate recovery per completion. Most of the GOM Reserve Appreciation is in the shelf, reflecting the location of most of the existing fields. Reserve Appreciation for New Fields is included in the New Field hydrocarbon volume.

Figure S-22. Natural Gas Annual Production

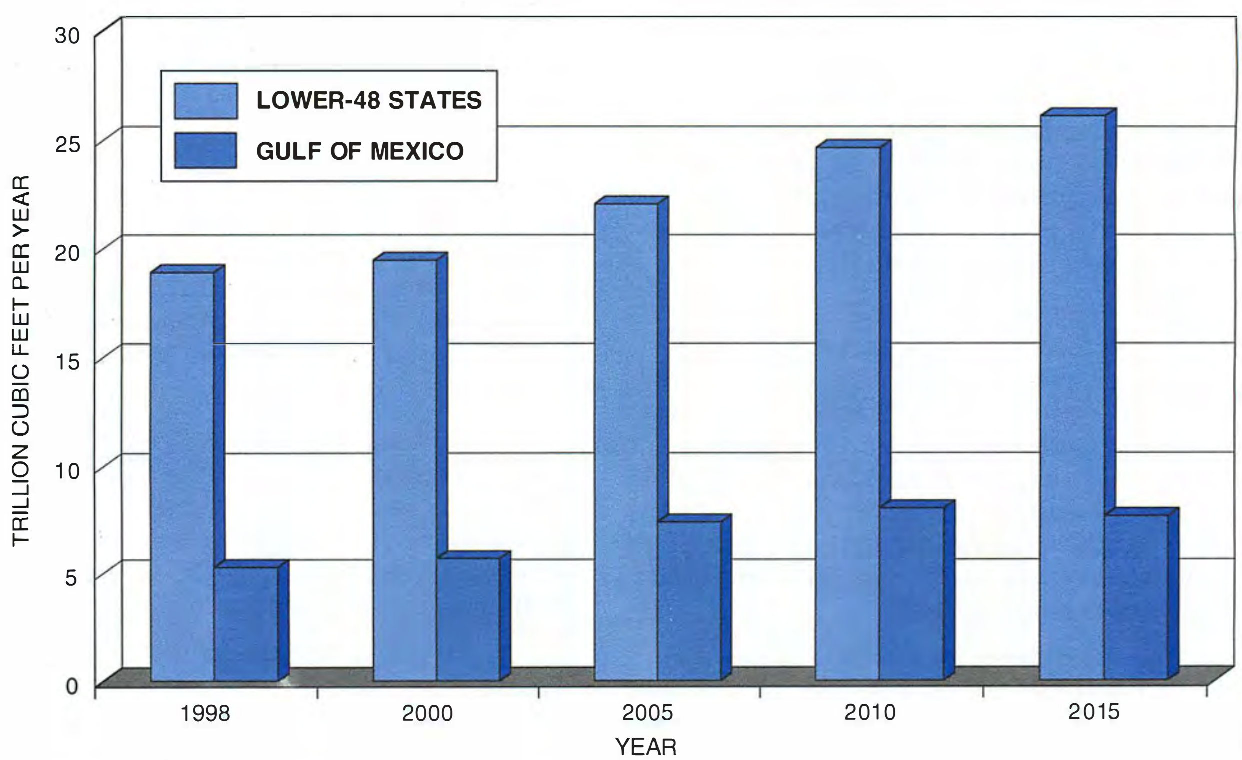


Figure S-23. Natural Gas Proved Reserves

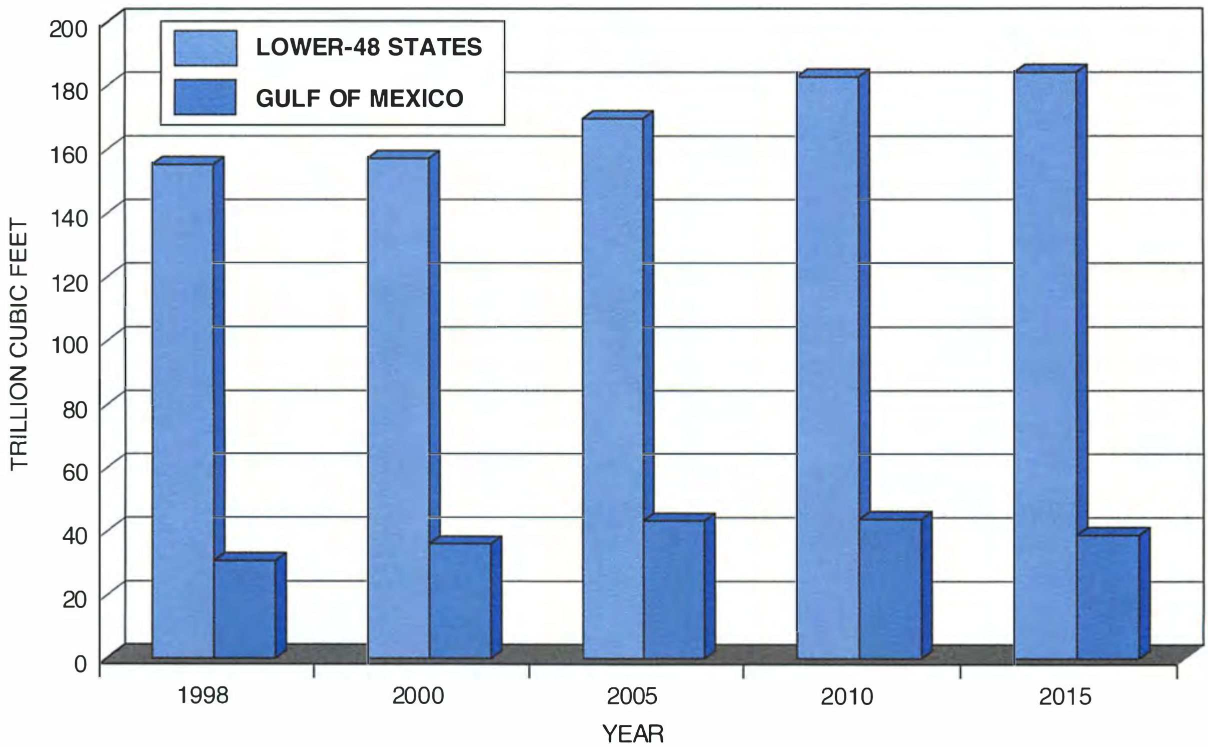
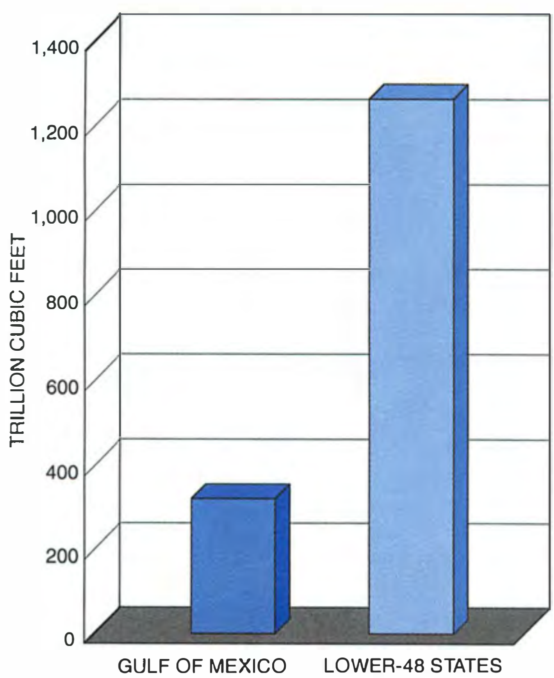


Figure S-24. Natural Gas Assessed Additional Resources



Comparisons of the New Field and Old Field Reserve Appreciation natural gas resource estimates for the Central & Western GOM from this study and recent estimates by the Minerals Management Service (MMS), the Potential Gas Committee (PGC), and the Gas Research Institute (GRI) are shown in Figures S-28 and S-29.

Cost Assumptions

Exploration, development, and pipeline costs for the GOM shelf region were based on scenarios developed in the 1992 Study. The specific cost numbers were updated for the 1999 Study based on recent industry studies.

Cost assumptions for the deepwater GOM differ between the various categories and are driven primarily by differences in water depth. Development options for surface completion and subsea were available dependent on field size and the gas/oil ratio.

Exploration and development costs change with time dependent on inflation factors and technology impacts.

Figure S-25. Water Depth Intervals of the Central & Western Gulf of Mexico

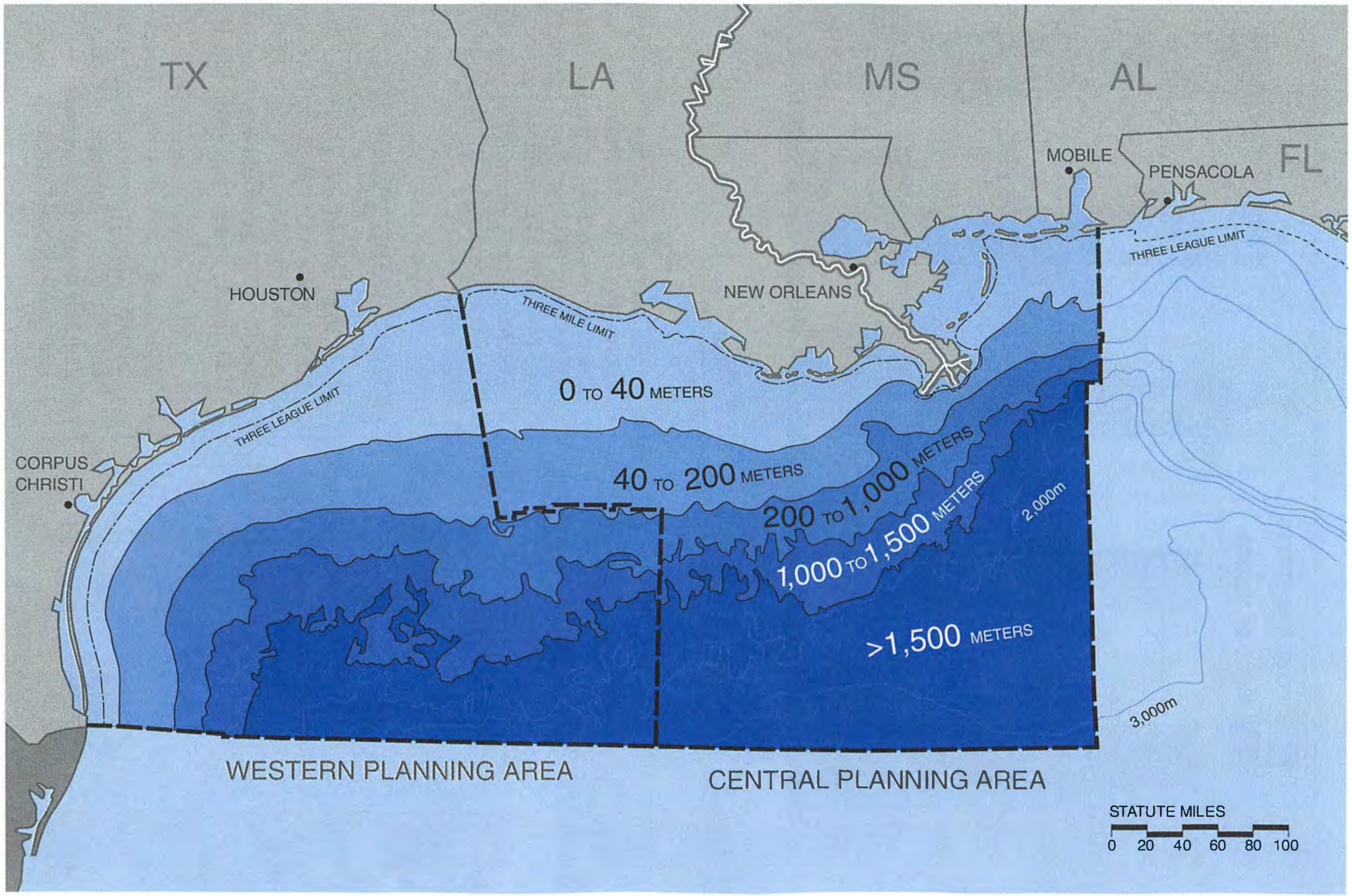
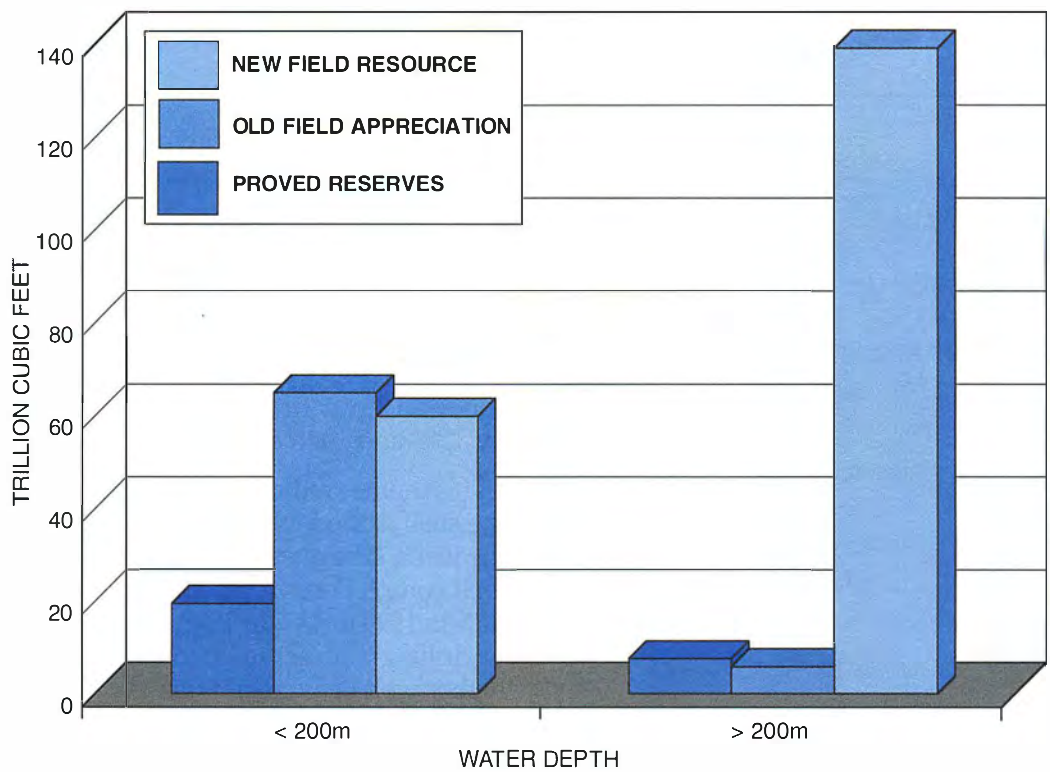


TABLE S-24

GULF OF MEXICO RESOURCES
(Billion Cubic Feet)

		Assessed Additional Resources					
	Proved Reserves	Old Field Appreciation	New Fields	Total Assessed Additional Resources	Total Remaining Resources	Cumulative Production	Total All-Time Recovery
Eastern	5,700	2,160	40,655	42,815	48,515	1,500	50,015
Central & Western	26,927	70,661	205,328	275,989	302,916	141,843	444,759
Total	**32,627**	**72,821**	**245,983**	**318,804**	**351,431**	**143,343**	**494,774**

Figure S-26. Central & Western Gulf of Mexico Natural Gas Resource



Production Decline and Reserve Appreciation Assumptions

Although the deepwater gas production is forecast to increase dramatically, the shelf region has been and at present is the most significant contributor to gas production in the GOM. The Reserve Appreciation potential, based on existing fields, is estimated to be 65 TCF for the Central & Western GOM shelf and 8 TCF for the rest of the GOM. The decline of existing production and the decline

Figure S-27. Eastern Gulf of Mexico Natural Gas Resource

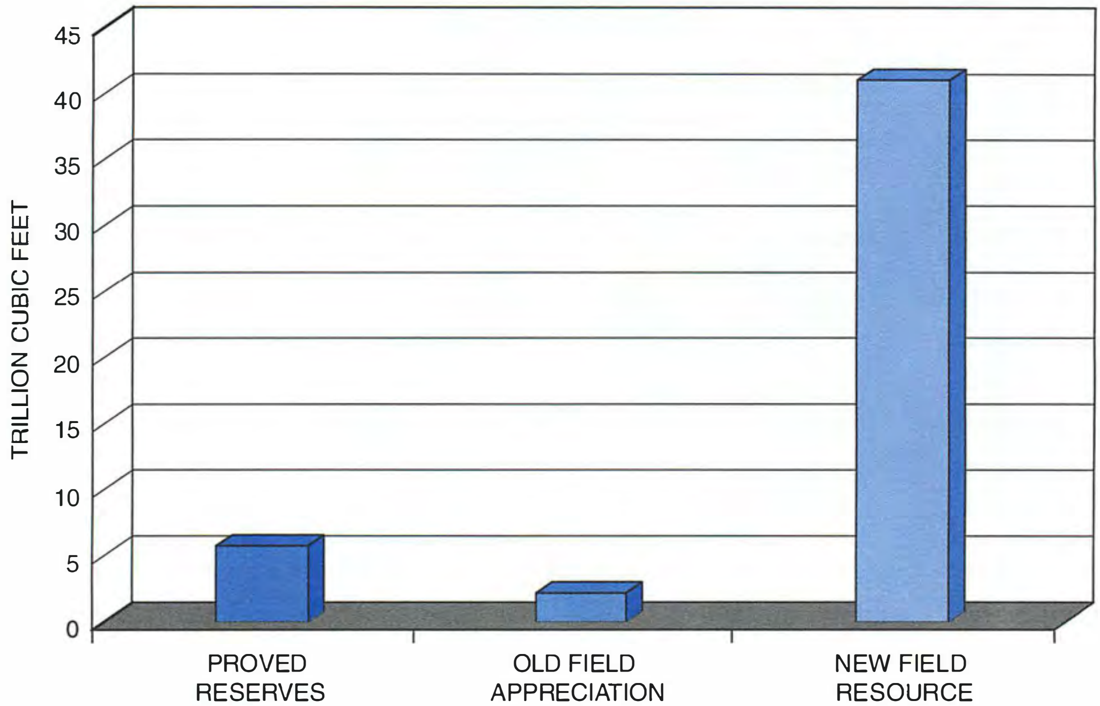


TABLE S-25

HYDROCARBON YIELD AND GAS/OIL RATIO ASSUMPTIONS FOR CENTRAL & WESTERN GULF OF MEXICO

Category (Water Depths)	Hydrocarbon Yield (Million BOE per Cubic Mile)	Gas/Oil Ratio (BOE Basis)
0-40m	0.35	74/26
40-200m	0.40	74/26
200-1,000m	0.45	40/60
1,000-1,500m	0.22	34/66
+1,500m	0.17	35/65

rate for Reserve Appreciation additions are critical factors in estimating GOM production.

One indicator of the gas production trend in the GOM is the proved reserves/production ratio (R/P). Figure S-30 shows the recent R/P trends for the GOM. The overall R/P trend for the GOM has been stable due to the impact of deepwater wells. However, the R/P for the shelf has dropped through the 1990s from 5.4 to 4.5. The shelf reduction in R/P is a function both of decreasing proved reserves by 12% and increasing production by 6%.

Another indicator of the production trend in the shelf is the high decline rates seen in some of the wells. The average annual decline rate for gas well completions in the shelf has increased from 31% in 1994 to 43% in 1998. Technology advances in drilling and completion practices resulting in higher well deliverability have contributed to the increase in well decline rates. However, there are concerns that the high decline rates are an indication of a possible drop in well ultimate recovery and in region gas potential, particularly Reserve Appreciation opportunities. Also, the high decline rates result in a requirement for steady investment to sustain a rapid treadmill of development and production.

Historical data of Estimated Ultimate Recovery (EUR) per completion were used to

Figure S-28. Comparison of New Field Natural Gas Resource Estimates for Central & Western Gulf of Mexico

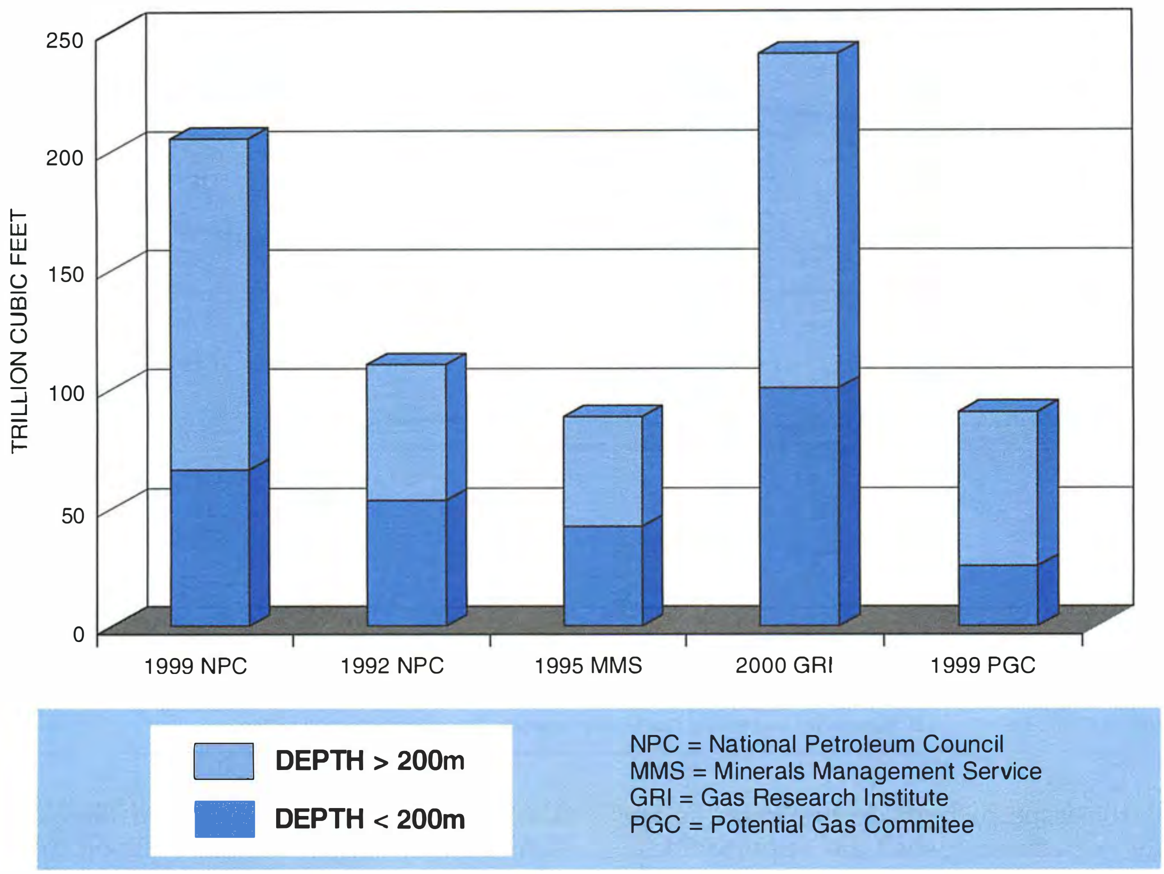


Figure S-29. Comparison of Old Field Appreciation Natural Gas Resource Estimate for Central & Western Gulf of Mexico

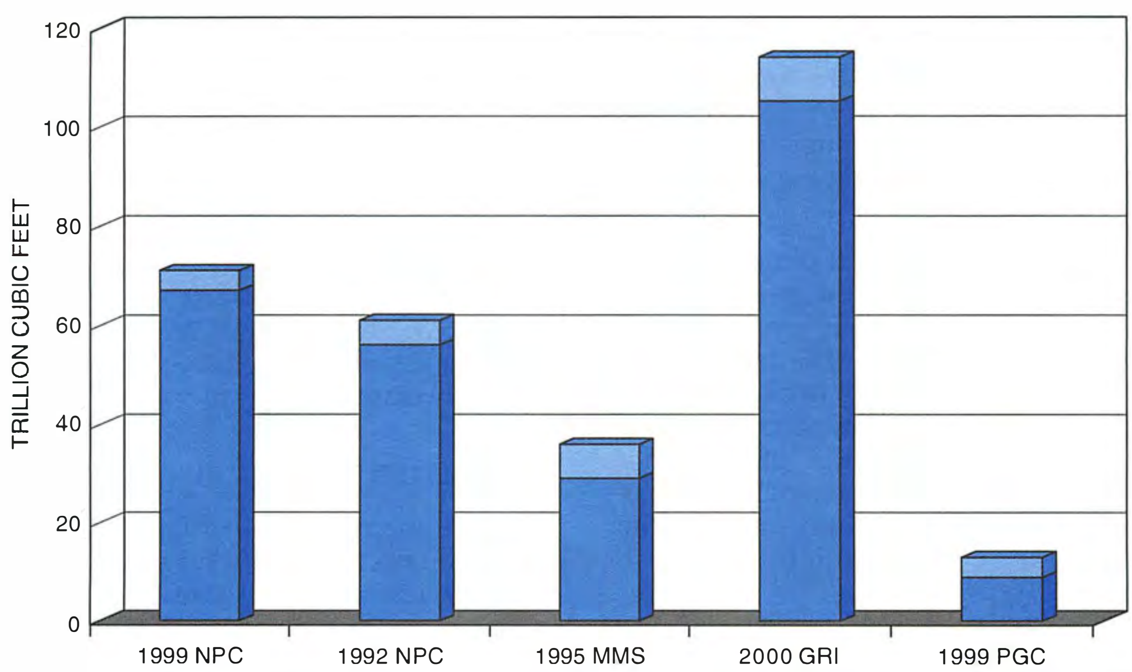
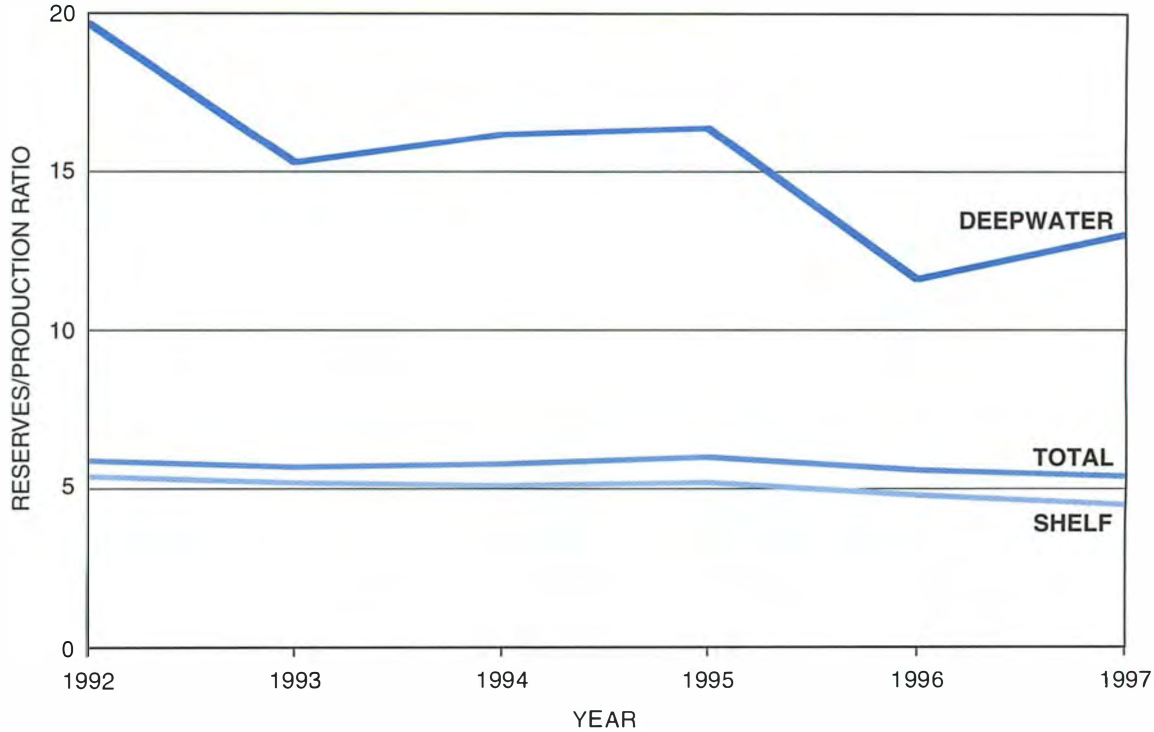


Figure S-30. Gulf of Mexico Proved Reserves/Production Ratio



SOURCE: DOE/EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* Annual Reports, various years.

address the issue of high decline rates as an indicator of decreasing shelf gas opportunities. Figure S-31 shows the EUR per shelf gas completion for various types of completions during the period 1992 through 1997. The data show a relatively constant trend of approximately 4.5 BCF per gas completion for the total shelf. The data also show the variation between the completion types indicating the impact of the completion type mix. Figure S-32 shows the relative percentage of each completion type for gas completion activity during the period 1992 to 1997.

The production and EUR per completion data were used to estimate the trends in R/P and EUR per completion for Reserve Appreciation opportunities. The forecast rate used in the model for annual decline in existing production and additions of new wells is consistent with the present R/P of 4.5 with a decreasing R/P of approximately 2% per year. The EUR per gas completion used in the model for Reserve Appreciation was 4 BCF declining at 3.3% per year.

The GOM shelf has been a region requiring steady investment to maintain production. The stability of production from the Reserve Appreciation opportunities will be directly related to the stability of industry investments in this region.

Production and Reserve Forecast

The production and reserves for the GOM are forecast to increase significantly, as shown in Figures S-33 and S-34 (breakout of Central & Western GOM and Eastern GOM).

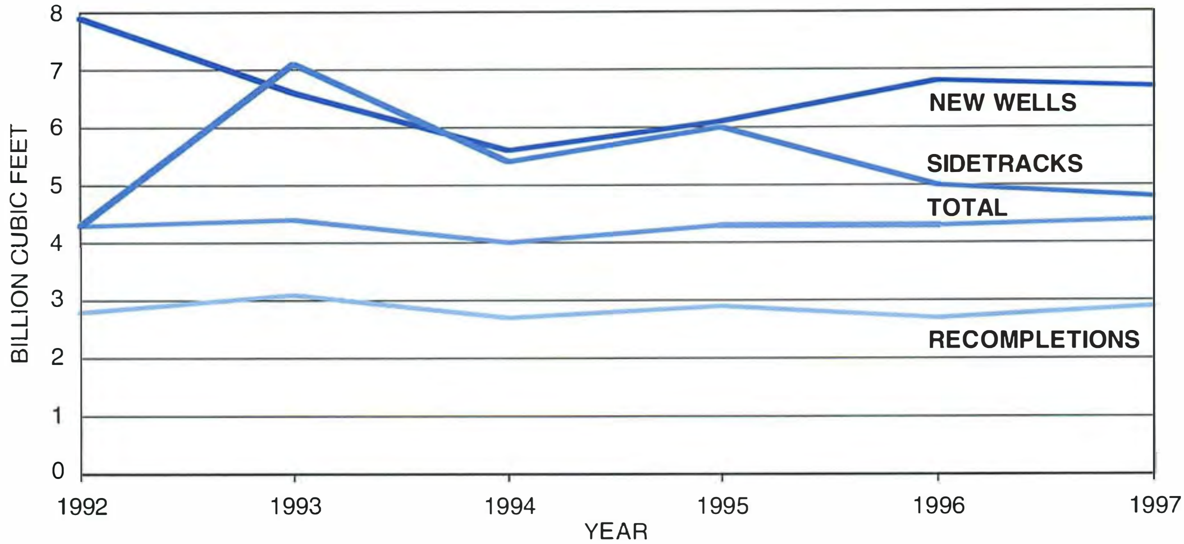
A more detailed understanding of the contributing areas can be seen in Figure S-35, which shows the production forecast by water depths for the Central & Western GOM. Figure S-36 shows the GOM drilling activity by water depth. These figures depict the continued increase in deepwater activity.

Infrastructure Requirements

The increase in GOM production and reserves reflects a significant increase in deepwater drilling activity, as shown in Figure S-36.

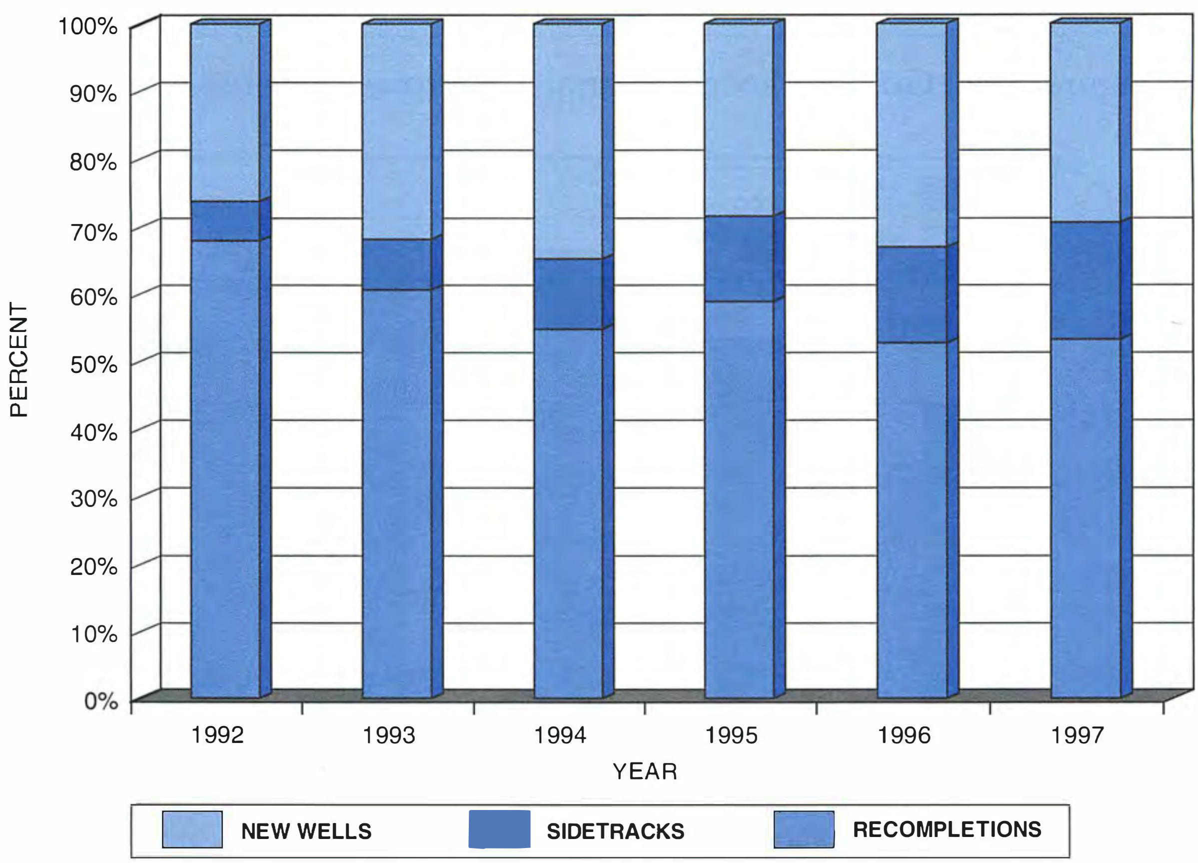
Table S-26 shows for the forecast period the required number of deepwater mobile

Figure S-31. Gulf of Mexico Shelf Gas Well Estimated Ultimate Recovery per Completion



SOURCE: Energy and Environmental Analysis, Inc., from PI/Dwights data bases.

Figure S-32. Gulf of Mexico Shelf Gas Well Completion Mix



SOURCE: Energy and Environmental Analysis, Inc., from PI/Dwights data bases.

Figure S-33. Gulf of Mexico Natural Gas Production Forecast

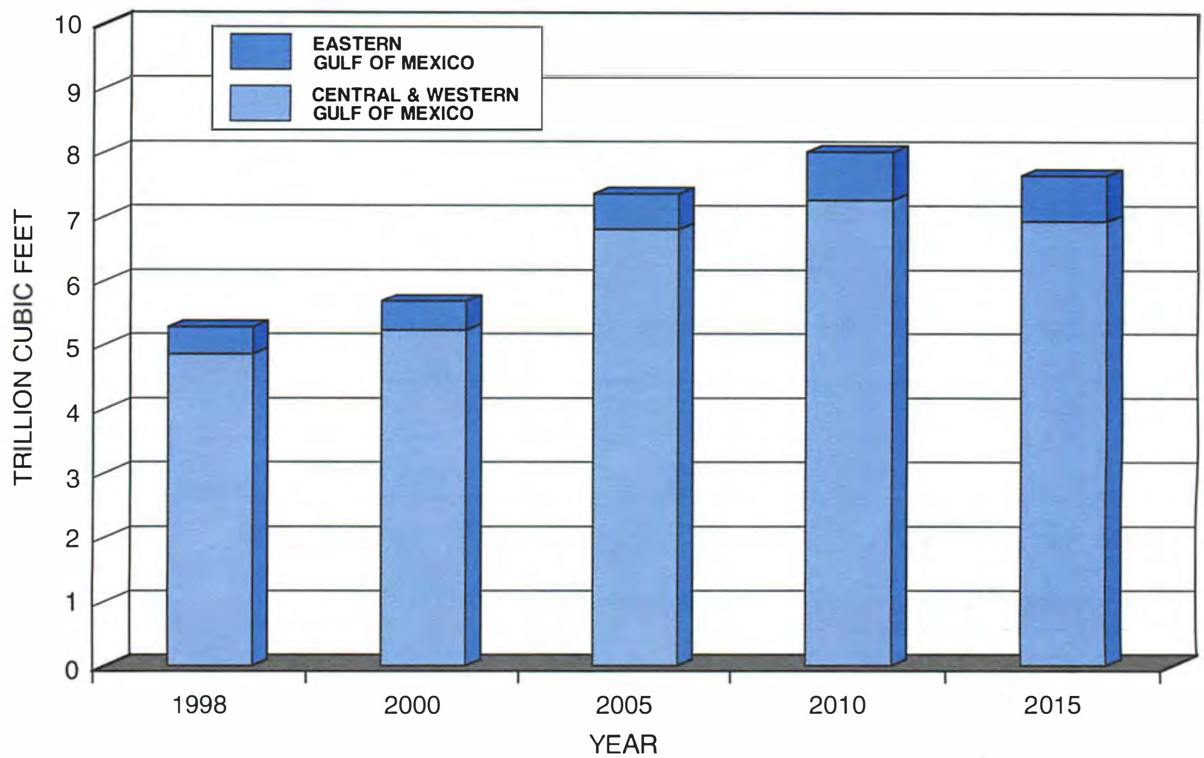


Figure S-34. Gulf of Mexico Natural Gas Proved Reserve Forecast

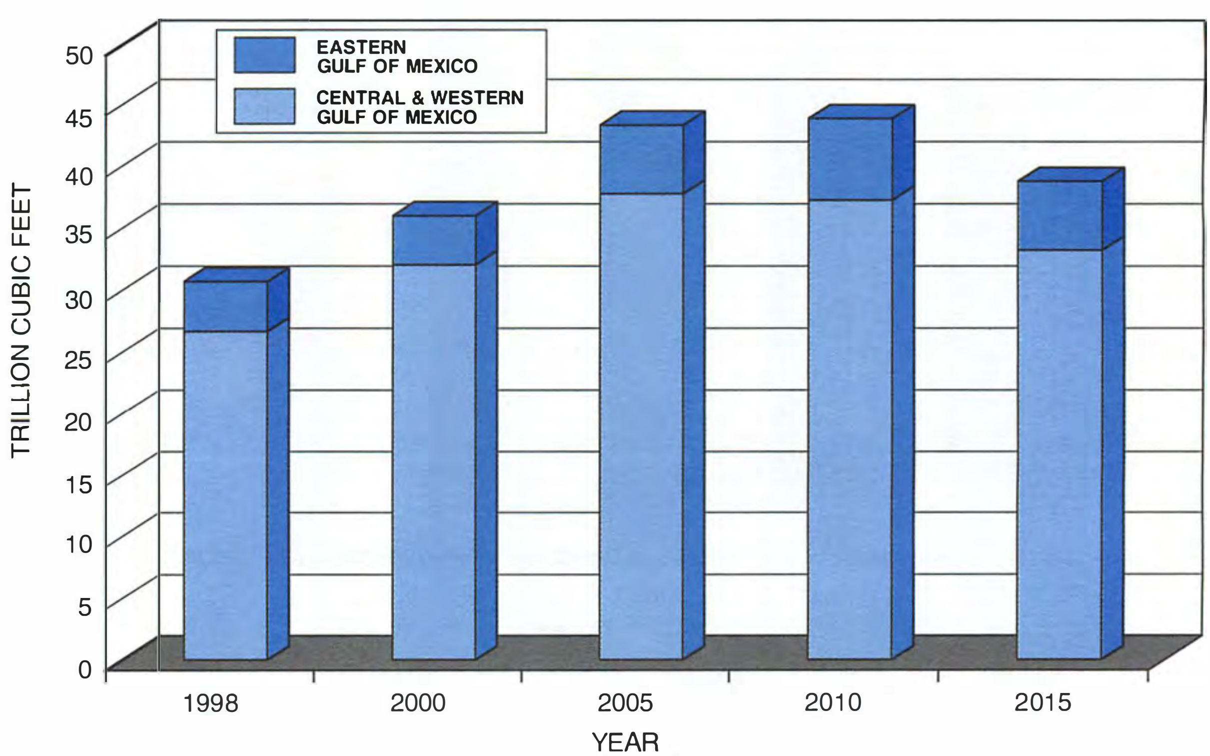


Figure S-35. Gulf of Mexico Natural Gas Production by Water Depth

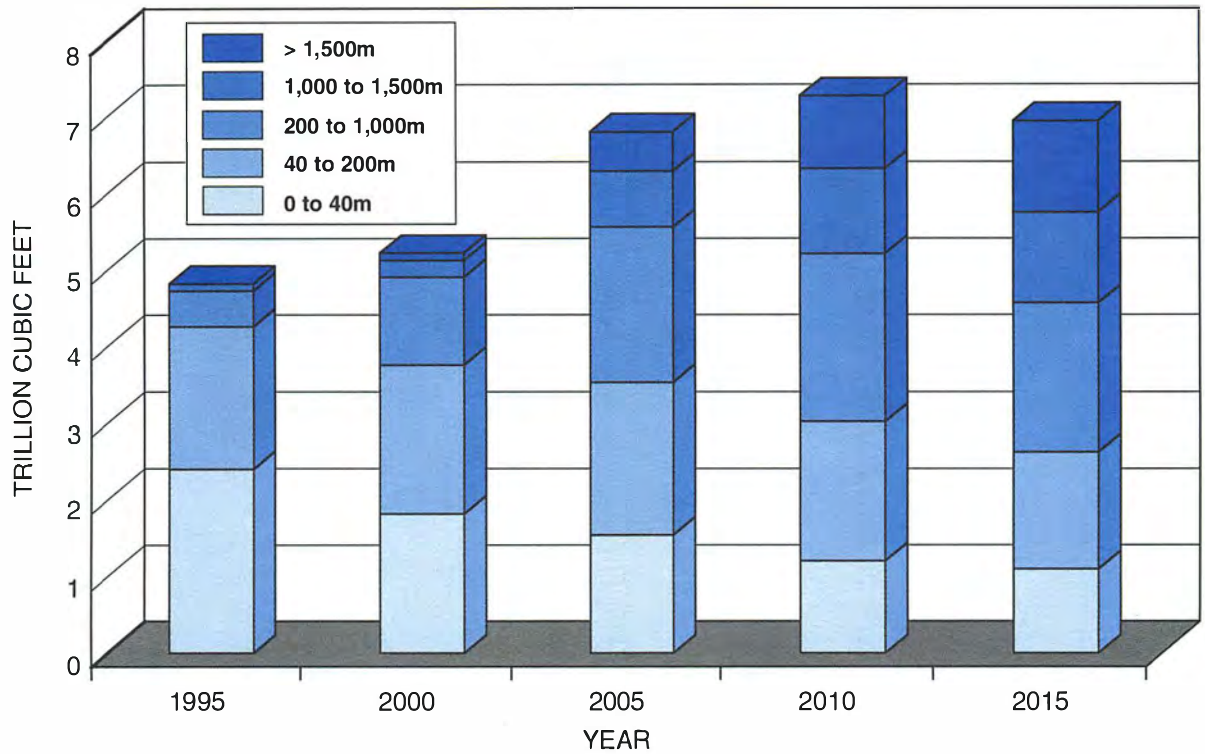


Figure S-36. Gulf of Mexico Drilling Activity by Water Depth

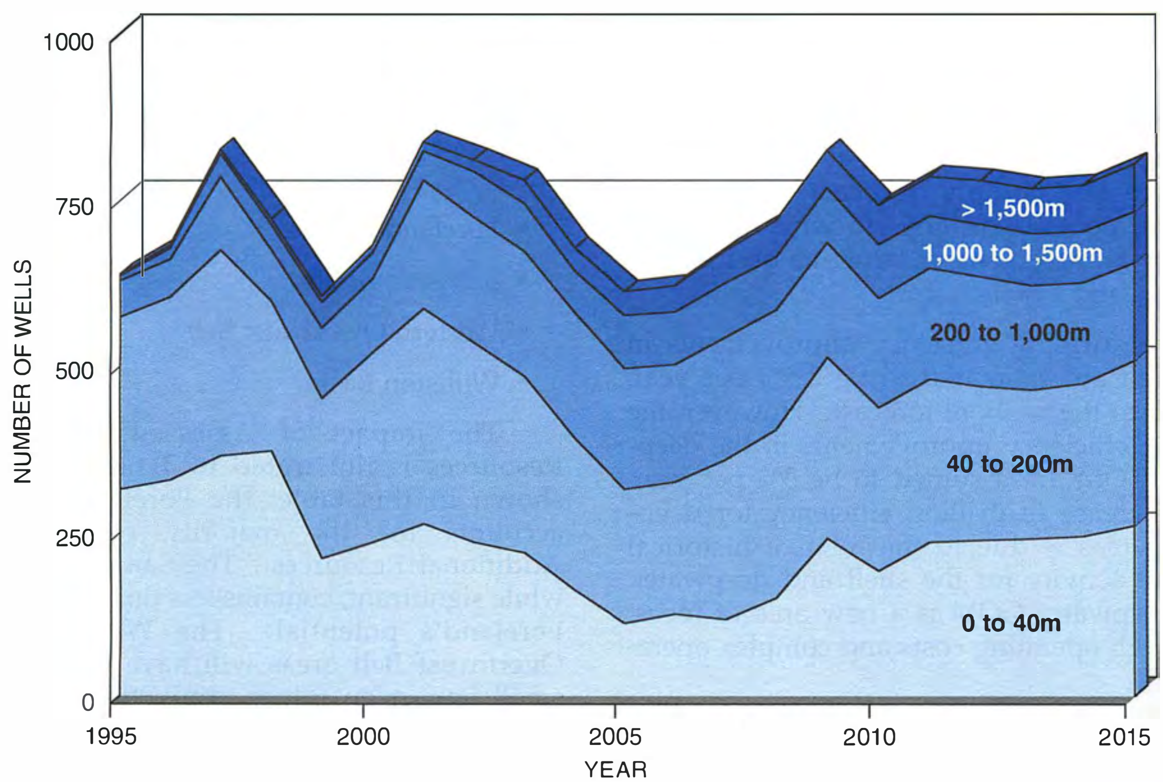


TABLE S-26

EXISTING AND REQUIRED CENTRAL & WESTERN GULF OF MEXICO MOBILE DRILLING RIGS BY WATER DEPTH CATEGORY

	200 to 1,000m		1,000 to 1,500m		1,500m+		Total	
Year	Available Mobile Rigs	Rigs Required	Available Mobile Rigs	Rigs Required	Available Mobile Rigs	Rigs Required	Available Mobile Rigs	Rigs Required
2000	15	19	11	7	19	2	45	28
2001	15	33	12	7	26	2	53	42
2002	15	32	12	12	26	3	53	47
2003	14	31	12	12	26	6	52	49
2004	14	31	12	10	26	6	52	47
2005	14	29	12	13	26	6	52	48
2006	13	28	12	12	26	6	51	46
2007	13	29	12	13	26	8	51	50
2008	13	28	12	12	26	8	51	48
2009	12	26	12	12	26	9	50	47
2010	12	25	12	12	26	9	50	46
2011	11	24	11	12	26	9	48	45
2012	10	24	10	11	25	10	45	45
2013	10	22	10	11	23	10	43	43
2014	9	21	10	11	22	10	41	42
2015	9	20	9	11	21	10	39	41

drilling rigs by water depth category along with the available (existing or planned as of 1-1-99) drilling rigs.

Technology Assumptions

There were two significant technology assumptions specific to the GOM that were used in the supply forecast: technology improvements in drilling efficiency and technology improvements in structure design, fabrication, and installation.

The drilling efficiency improvements in the shelf are estimated to be 2.5% per year, similar to the onshore forecast. However, the drilling efficiency improvements in the deepwater GOM are assumed to be 3% per year. This increase in drilling efficiency for deepwater areas is due to the relative historical level of activity for the shelf and deepwater. The deepwater GOM is a new area of focus, with high operating costs and complex operations.

Improvements in structure design, fabrication, and installation were forecast for the Reference Case to be 1.5% per year. The estimate for the Faster Technology Advancement case is 4% per year.

Rocky Mountains

In our analysis of the Rocky Mountain area, four different HSM regions were evaluated:

- Foreland Region
- San Juan Basin
- Western Overthrust Belt
- Williston Basin.

The impact of Assessed Additional Resources is illustrated in Table S-27. As shown in this table, the Foreland Region accounts for the majority of Assessed Additional Resources. The San Juan Basin, while significant, contains less than 10% of the Foreland's potential. The Williston and Overthrust Belt areas will have a relatively small impact on future production from the Rockies. Because of this, the major emphasis of our analysis was in the Foreland Region and the San Juan Basin.

TABLE S-27

ROCKY MOUNTAIN RESOURCES
(Billion Cubic Feet)

		Assessed Additional Resources								
	Proved Reserves	Old Field Apprecia-tion	New Fields	Coalbed Methane	Tight Gas	Other*	Total Assessed Additional Resources	Total Remaining Resources	Cumulative Production	Total All-Time Recovery
Foreland Region	17,312	28,949	99,180	29,371	136,972	14,689	309,161	326,473	30,038	356,511
San Juan Basin	14,872	11,673	2,209	10,058	0	0	23,940	38,812	21,482	60,294
Overthrust Belt	2,917	702	6,731	0	0	0	7,433	10,350	1,700	12,050
Williston Basin	1,241	2,653	3,088	0	0	0	5,741	6,982	4,488	11,470
Total	**36,342**	**43,977**	**111,208**	**39,429**	**136,972**	**14,689**	**346,275**	**382,617**	**57,708**	**440,325**

*Primarily low-Btu gas.

The Rocky Mountain areas discussed above currently account for approximately 14% of lower-48 gas production, and this will increase to nearly 18% by 2015. Production growth from this area will be a major factor in meeting growing U.S. demand for natural gas.

The projection of Rocky Mountain gas, by model area, is as shown in Figure S-37. As can be seen in Figure S-37, the Foreland region will be the major growth area for the Rockies. An analysis of the area is following.

Foreland Region

The projection of Foreland natural gas production is shown in Figure S-38. As can be seen in Figure S-38, nonconventional gas supplies, principally coalbed methane and tight gas, will be the driving force behind higher production. Regarding coalbed methane, as illustrated in Figure S-39, the Powder River, Green River, Uinta, and Piceance Basins will be areas of higher coalbed methane production.

Technology will be critical for the development of these nonconventional resources. Figures S-40 and S-41, based on the Reference Case assumptions, show the impact of the evolution of technology on the growth of nonconventional gas sources such as coalbed methane and tight gas.

Figure S-42 shows the Supply Task Group's estimates of future drilling in the Foreland Region.

San Juan Basin

Production from the San Juan Basin has more than doubled since the 1992 Study, to about 1,500 BCF per year. This was due to development of the Fruitland coalbed methane interval. It is projected that the Fruitland will start its natural decline in the next several years. Production from the Mesa Verde (Low Permiability) will grow, but not to the extent needed to completely compensate for the anticipated decline of the Fruitland, as shown in Figure S-43.

Well count projections for the San Juan Basin are shown in Figure S-44. The higher drilling activity is a function of denser well spacing in both the Fruitland coalbed methane and tight gas intervals.

Figure S-37. Rocky Mountain Gas Production

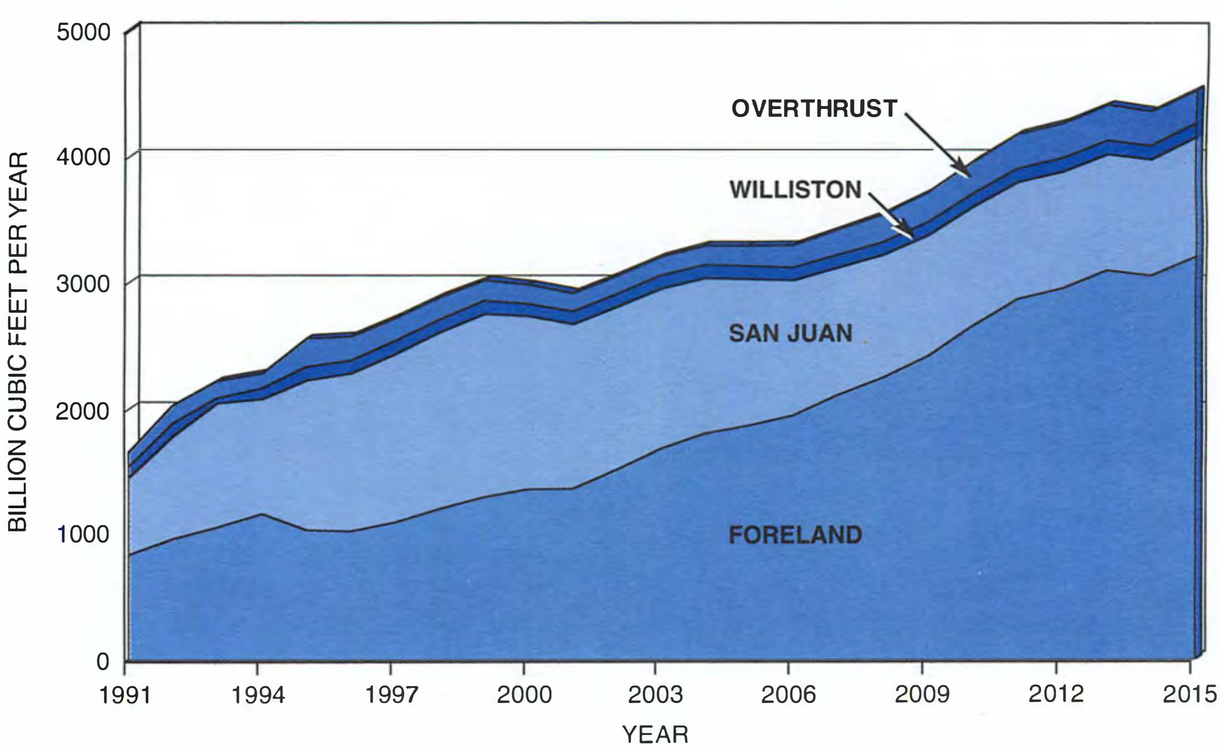


Figure S-38. Foreland Region Gas Production

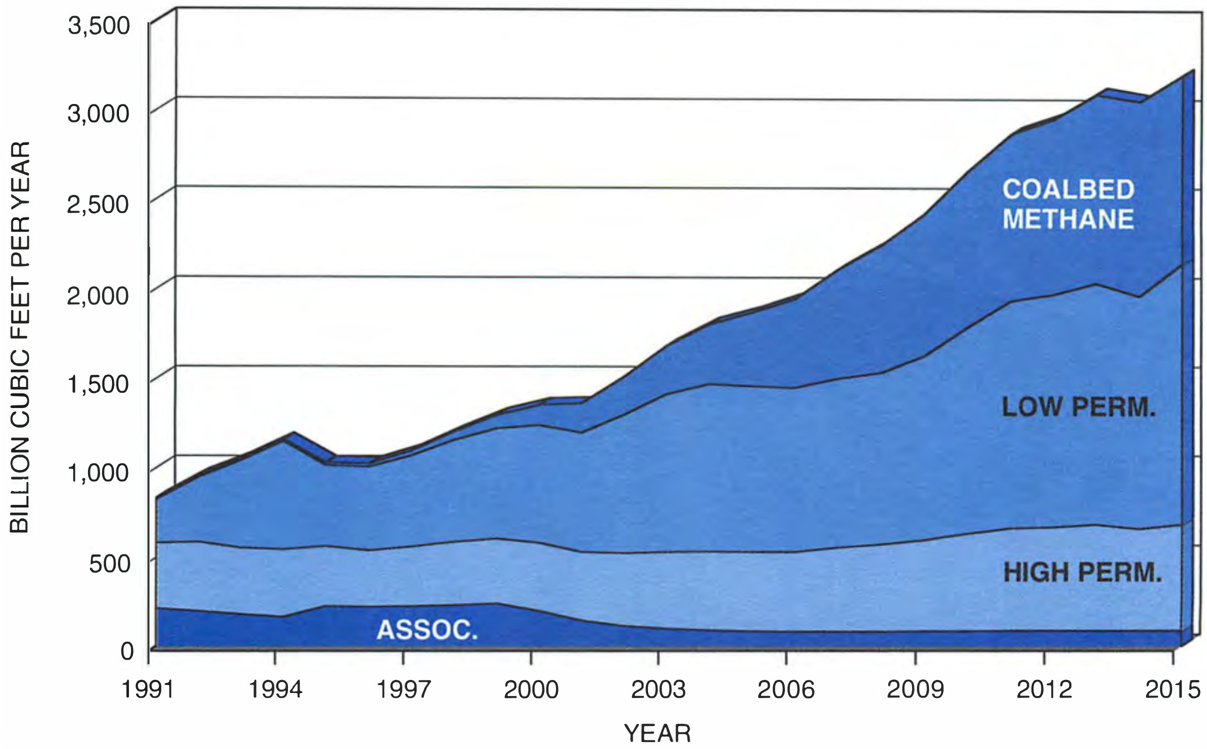


Figure S-39. Foreland Region Coalbed Methane Production

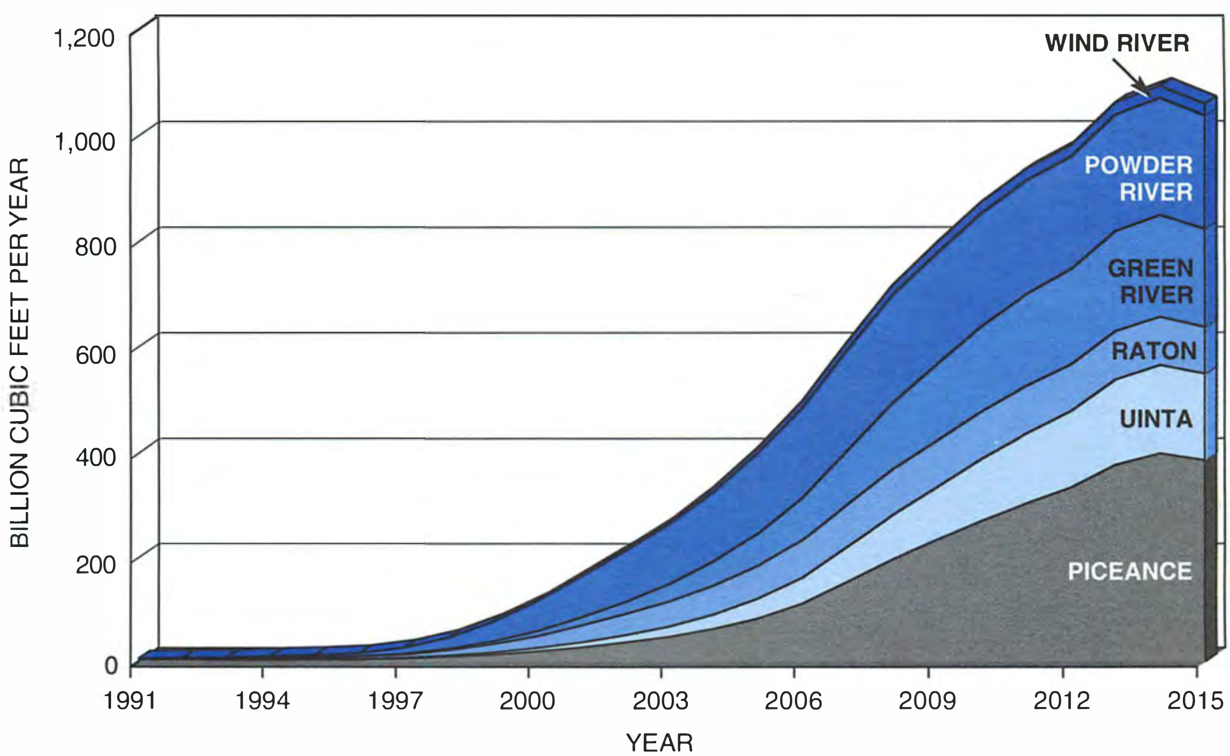


Figure S-40. Foreland Region Coalbed Methane Recoverable Resource and Amount Proved in Projection

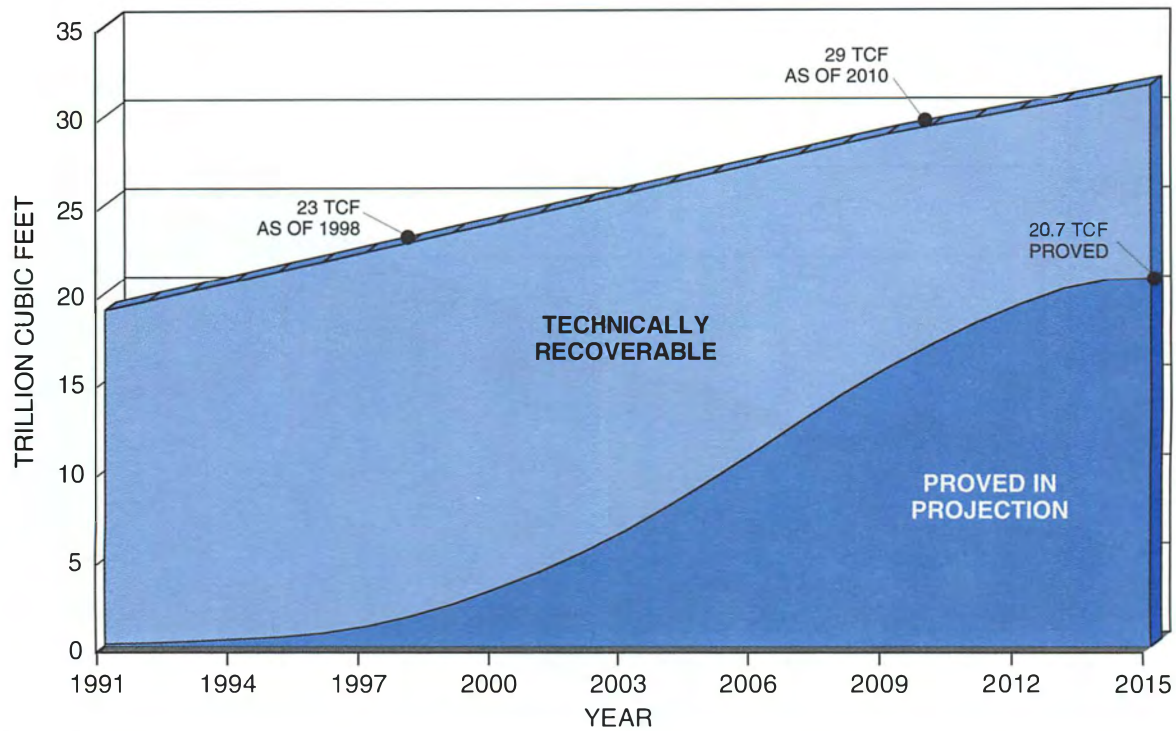


Figure S-41. Foreland Region Tight Gas Recoverable Resource and Amount Proved in Projection

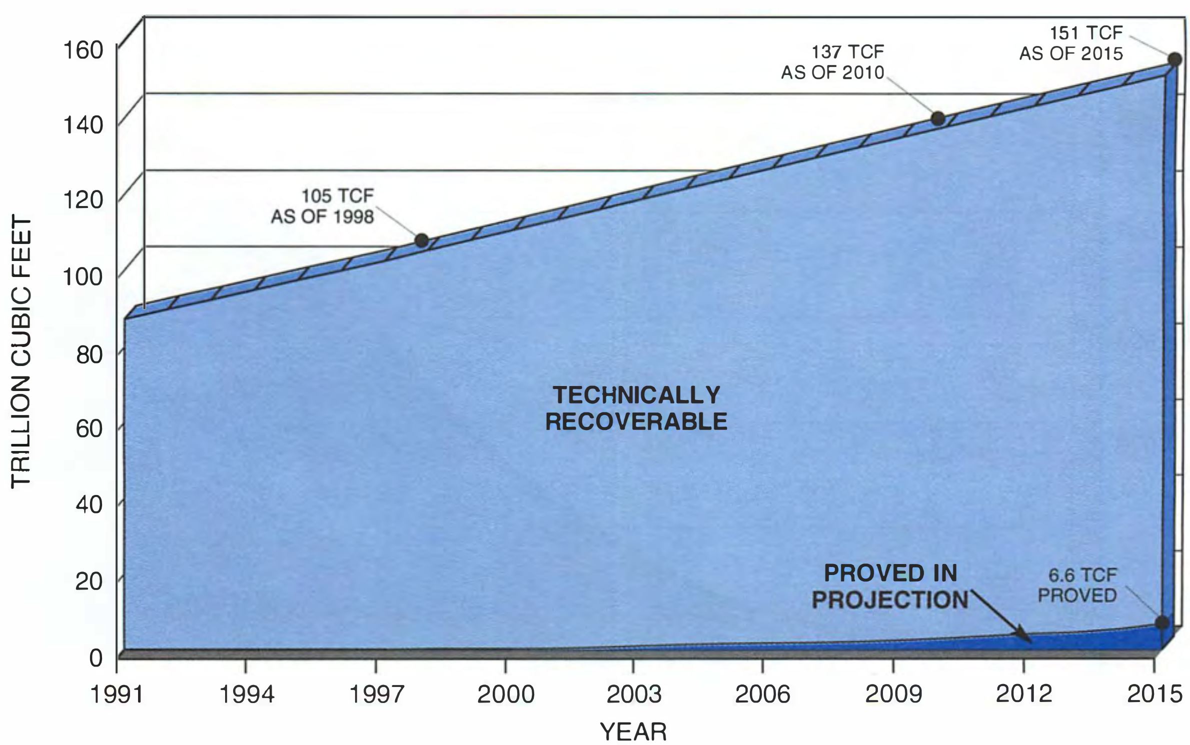


Figure S-42. Foreland Region Drilling Projection

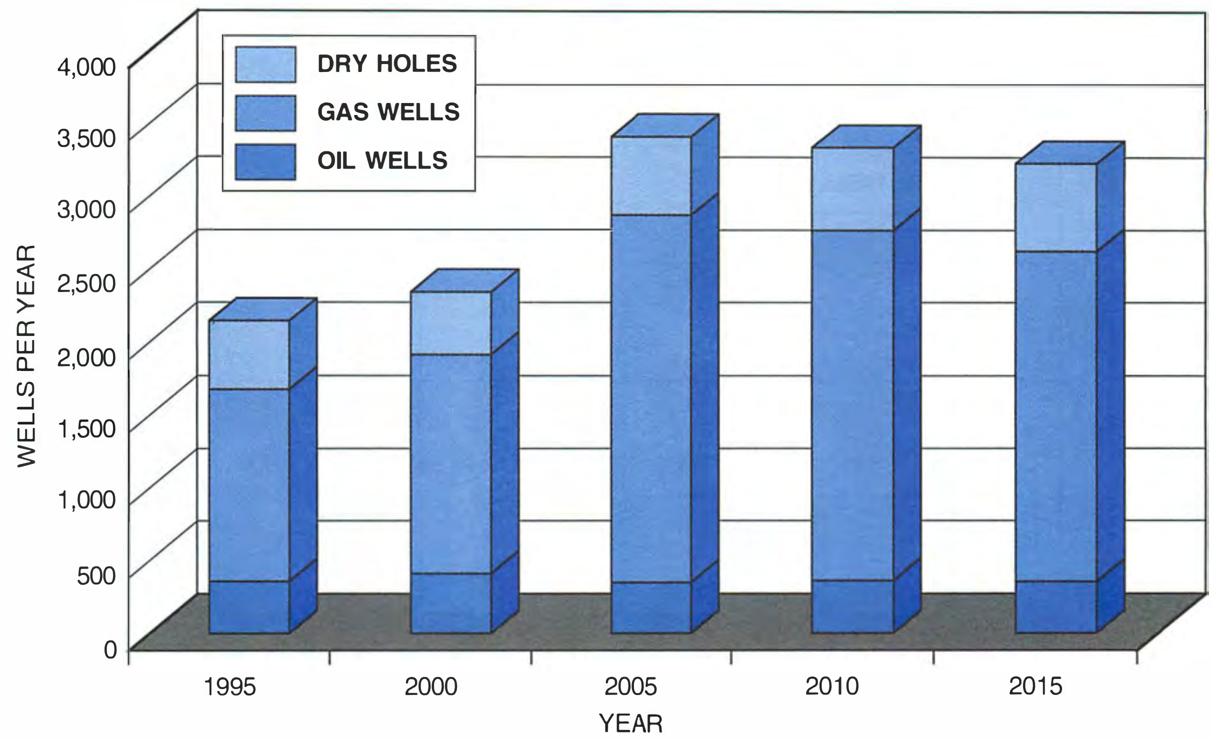


Figure S-43. San Juan Basin Gas Production

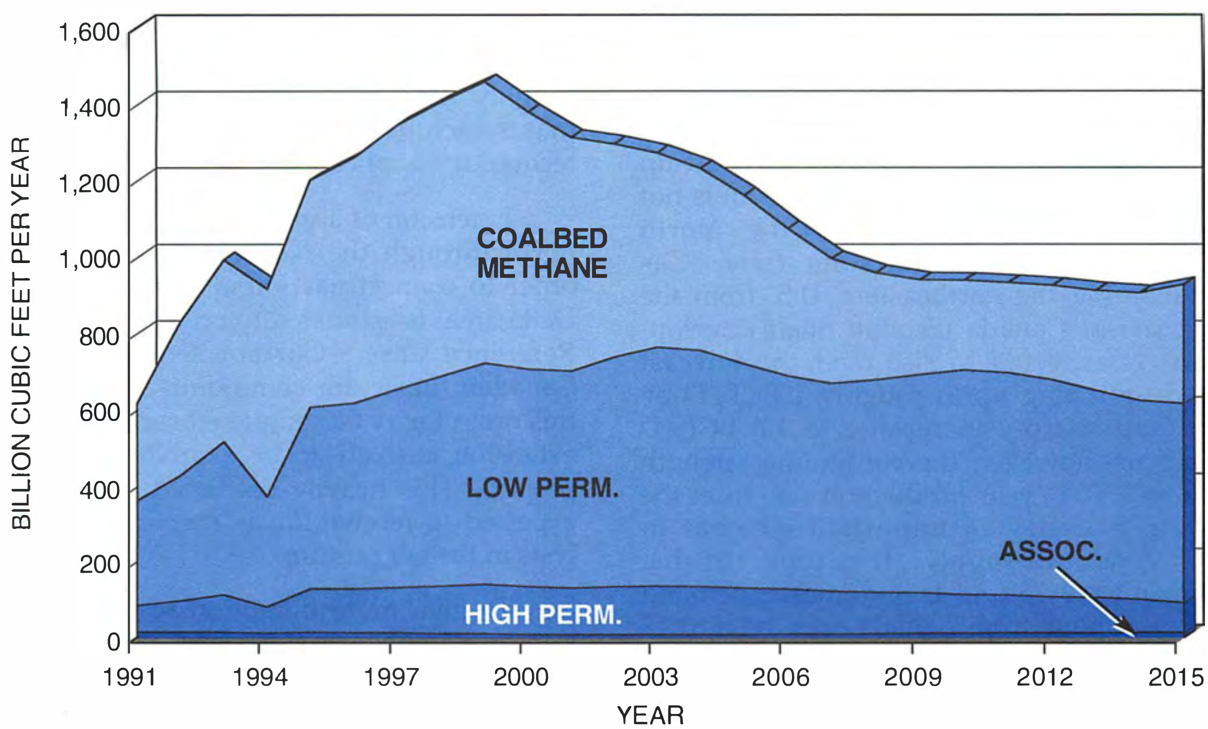
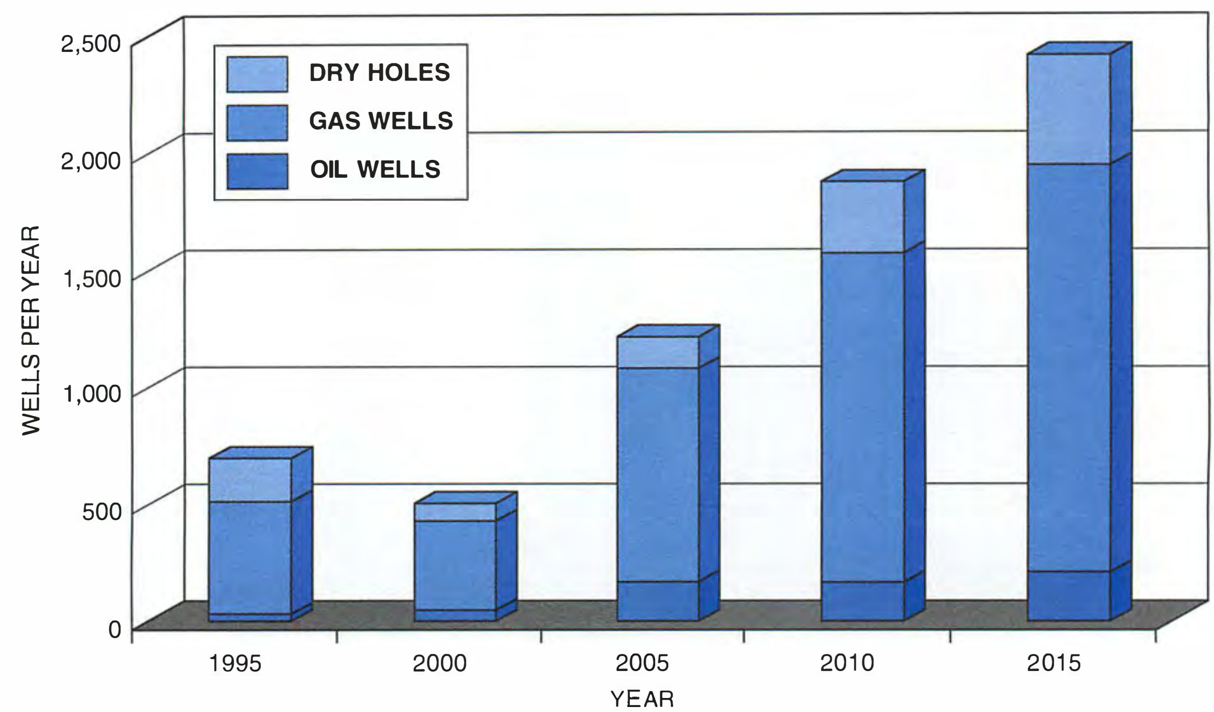


Figure S-44. San Juan Basin Drilling Projection



Canada

The performance of the natural gas upstream industry in Canada will continue to have a significant impact on domestic supply. The Western Canadian Sedimentary Basin dominates the natural gas supply role in Canada; gas either currently inventoried as frontier or still to be found north of current pipeline infrastructure (following the start-up of the Alliance Pipeline project in 2000) is not expected to be available to the North American supply grid for some time. Gas now entering the northeastern U.S. from the east coast of Canada (Scotian Shelf developments) is expected to rise over the forecast period—ramping up to roughly 1 BCF/D by 2010 (and sharply increasing to 1.6 BCF/D thereafter); however, the continuing strength of a 6 to 7 TCF/year production rate from the western basin is an important element in North American supply. It is projected that approximately 15% of U.S. domestic demand will be supplied from Canada over the next 15 years.

The 1999 Study assessment of the recoverable gas resource base for Canada is shown in Table S-28. The Total Remaining Resource of 667 TCF (about 10% proved), available to both Canadian and U.S. markets only with significant infrastructure additions at the extremities of current pipeline systems, compares to the modeled lower-48 resource base (proved plus estimated undiscovered gas) of roughly 1,466 TCF (11% proved). (Both estimates include the expectation of advanced technology applications.)

Extension of a western Canadian pipeline north through the Northwest Territories (in order to connect gas found in the Mackenzie Delta area) is estimated to occur in 2009 in the Reference Case. Current sentiment in the Canadian upstream community suggests that this project may be completed earlier; since the extension is likely to be a producer-initiated project. This heavily discussed possibility is expected to receive much attention from analysts in the near future.

To give more definition to the distribution and impact of Canadian gas supply on both current and future demands of the United States, Table S-29 shows regional production and total exports to the United States.

TABLE S-28

CANADIAN RESOURCES
(Billion Cubic Feet)

		Assessed Additional Resources								
	Proved Reserves	Old Field Apprecia-tion	Discovered Undeveloped	New Fields	Coalbed Methane	Tight Gas/ Other	Total Assessed Additional Resources	Total Remaining Resources	Cumulative Production	Total All-Time Recovery
Alberta, Manitoba, Saskatchewan	51,864	18,620	0	62,548	74,007	88,180	243,355	295,219	89,677	384,896
Br. Columbia	8,734	3,283	0	32,465	0	0	35,748	44,482	11,685	56,067
NW Canada	316	0	10,000	80,972	0	0	90,972	91,288	408	91,696
E. Canada	2,932	478	11,000	96,497	0	0	107,975	110,907	1,042	111,949
Arctic Canada	0	0	14,000	111,051	0	0	125,051	125,051	0	125,051
Total	**63,846**	**22,381**	**35,000**	**383,533**	**74,007**	**88,180**	**603,101**	**666,947**	**102,712**	**769,659**

TABLE S-29

PROJECTED GAS PRODUCTION IN CANADA BY REGION
(Trillion Cubic Feet per Year)

	1998	2000	2005	2010	2015
Alberta, Manitoba, Saskatchewan	5.0	5.4	6.1	5.8	5.6
British Columbia	0.6	0.7	0.8	1.1	1.2
Northwest Canada	–	–	–	0.1	0.6
Eastern Canada	0.01	0.015	0.2	0.4	0.8
Arctic Canada	–	–	–	–	–
		6.11	**7.1**	**7.4**	**8.2**
Modeled Exports to United States		3.1	3.7	3.7	4.3
% of U.S. Demand		13.4%	14.3%	13.1%	13.8%

Almost all of the gas produced in the projection comes from conventional reservoirs, with a minor contribution from coalbed methane.

The Reference Case production projection is shown graphically in Figure S-45. Historical and projected Canadian gas exports to the United States are expected to continue to increase, as shown in Figure S-46.

While the ability of the resource to supply markets in the United States has long been constrained by pipeline capacity, this is not expected to be a condition that characterizes future upstream performance of the Western Canadian Basin. New takeaway capacity has eliminated near-term pipeline constraints and the continued performance of the resource area is expected to be more affected by operations (short drilling seasons due to weather-related access constraints, together with access issues relating to land use in foothills and mountain area preserves) and by competitive demands from Canada's industrial, resource extraction, and power generating sectors. An effect of declining light oil production and the emergence of heavy oil as the dominant production stream will also impact gas supply over time, since light oil production is an associated gas "supplier," and heavy oil operations become more natural gas "consumers."

Therefore, while prospectivity of the western basin is perceived to be more extensive than analogous areas in the lower-48 states, drilling activity can only increase modestly in response to increased demand and stronger price incentives. Gas wells (almost all drilled in Alberta, Saskatchewan, and British Columbia) are expected to rise from roughly 3,500/year to over 5,000/year during the first half of the forecast period (see Figure S-46), and the effects of higher deliverability wells (drilled in currently unavailable regions), while perhaps more expensive and complicated, are projected to supply the deliverability that offsets normal (and increasingly stronger) production declines. The ability to drill at a rate of 14,000 wells/year (oil, gas, and dry holes) has been demonstrated as recently as 1997, and the new well count is expected to rebound to this level—only over the next five years. As mentioned, higher rate wells are expected from increasingly deeper and more complicated wells—but this delivery capacity

Figure S-45. Historical and Projected Gas Production in Canada

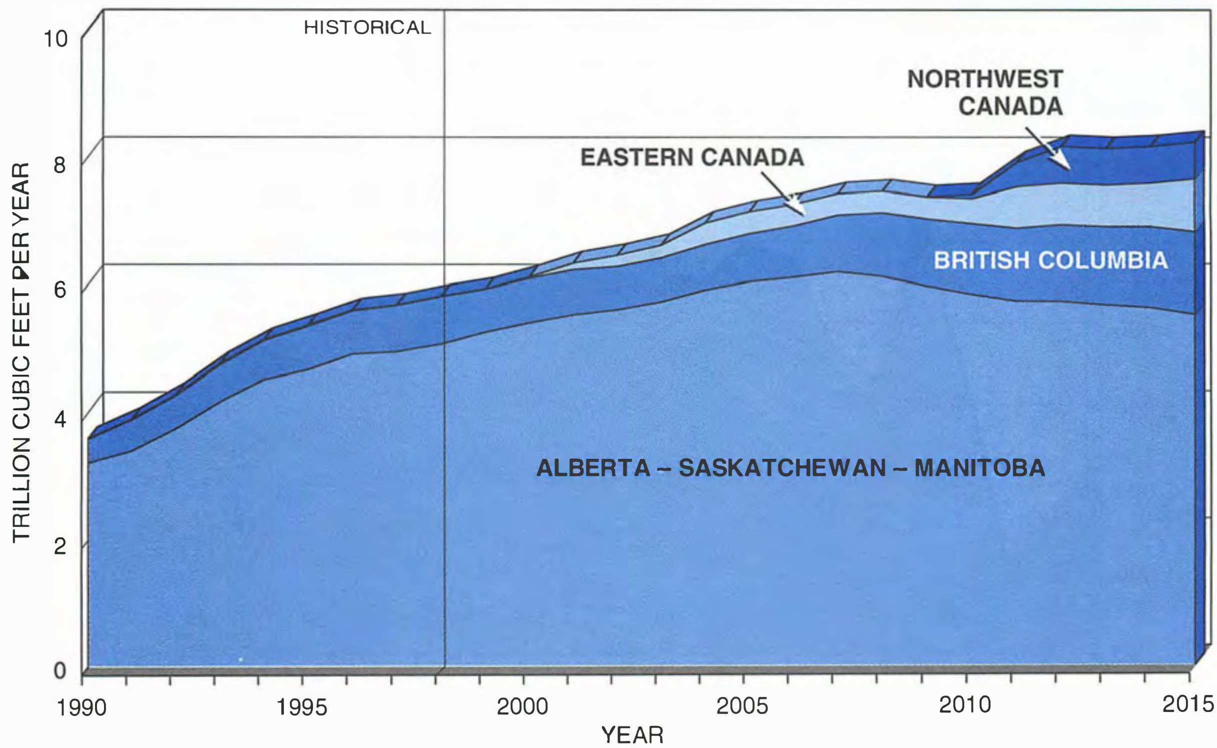


Figure S-46. Historical and Projected U.S. Gas Imports from Canada

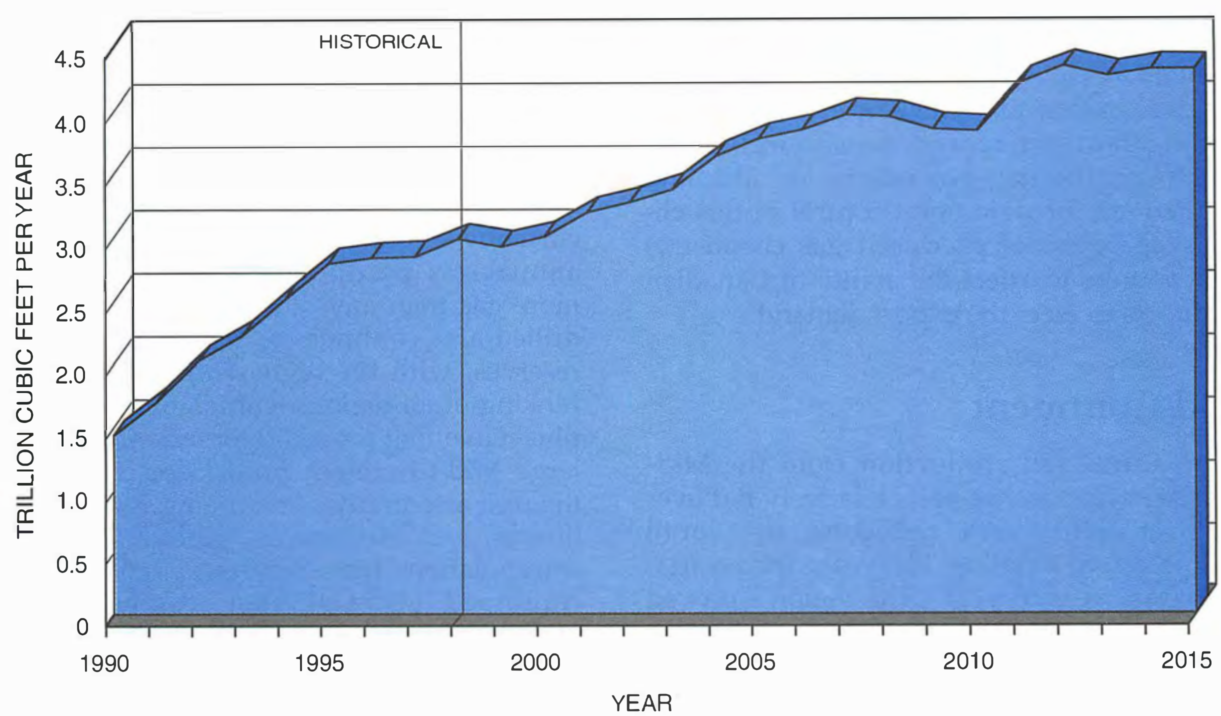
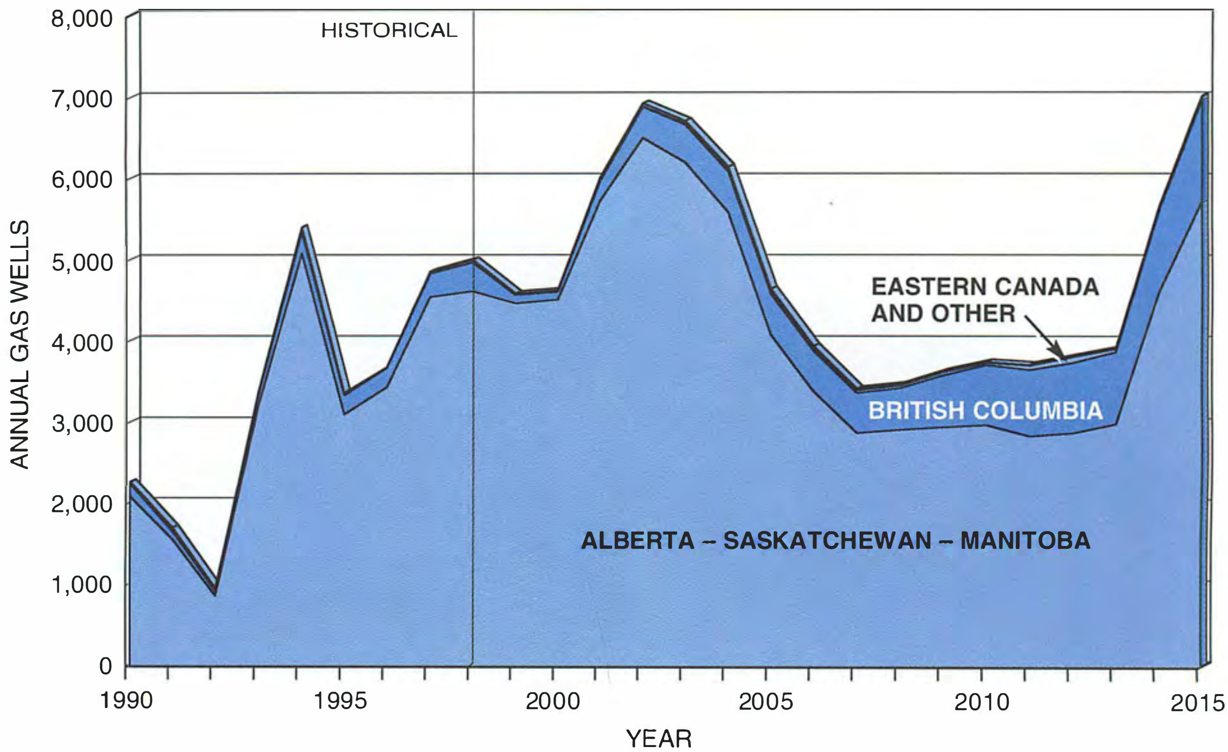


Figure S-47. Historical and Projected Gas Wells in Canada



may actually reduce the well activity rates back to a 7,000 to 8,000 wells per year level.

Despite the projected increase in new well capacity over the forecast period, strong price incentives (low differentials into the U.S. market) and abundant capital are required to maintain a healthy Canadian upstream oil and gas exploration and development industry. Drilling location access, deeper wells, and pipeline gathering/processing (an absolute requirement for dew point control in this climate regardless of produced gas chemistry) will continue to affect the ability of Canadian producers to meet the export demand.

Mid-Continent

Natural gas production from the Mid-Continent Region has been relatively flat over the past eight years, reflecting an overall decline approximating 1%/year; with variations from year to year. The region's proved reserves of 26 TCF represent 17% of the U.S. resource base (Table S-30).

Total Remaining Resources (proved plus unproved) of 138 TCF represent 9% of the estimated U.S. resource base. Recent production rates of just over 2.8 TCF/year comprise roughly 14-15% of the domestic production rate (Table S-31). Annual production developed from the model is expected to decline over the next 15 years, and as a result the volumes become less of a contributor to domestic production, and therefore a decreasing percentage amount of U.S. demand.

Representing 14–15% of the lower-48 production base, the Mid-Continent Region is currently second only to the Gulf of Mexico in annual gas production. Having produced more gas than any other region, this densely drilled area continues to rank high in proved reserves, with the highest ultimate recovery ranking of all regions (cumulative production plus remaining proved reserves). Consistently large Mid-Continent production volumes in the past also imply a continuing strong contribution over the forecast period. Statistical extrapolations from historical trends suggest continued Mid-Continent competitiveness with other supply regions (Figure S-48).

Recent drilling activity levels have been over 6,000 wells per year (oil, gas, and dry holes), with up to 2,000 gas wells per year.

TABLE S-30

MID-CONTINENT RESOURCES
(Billion Cubic Feet)

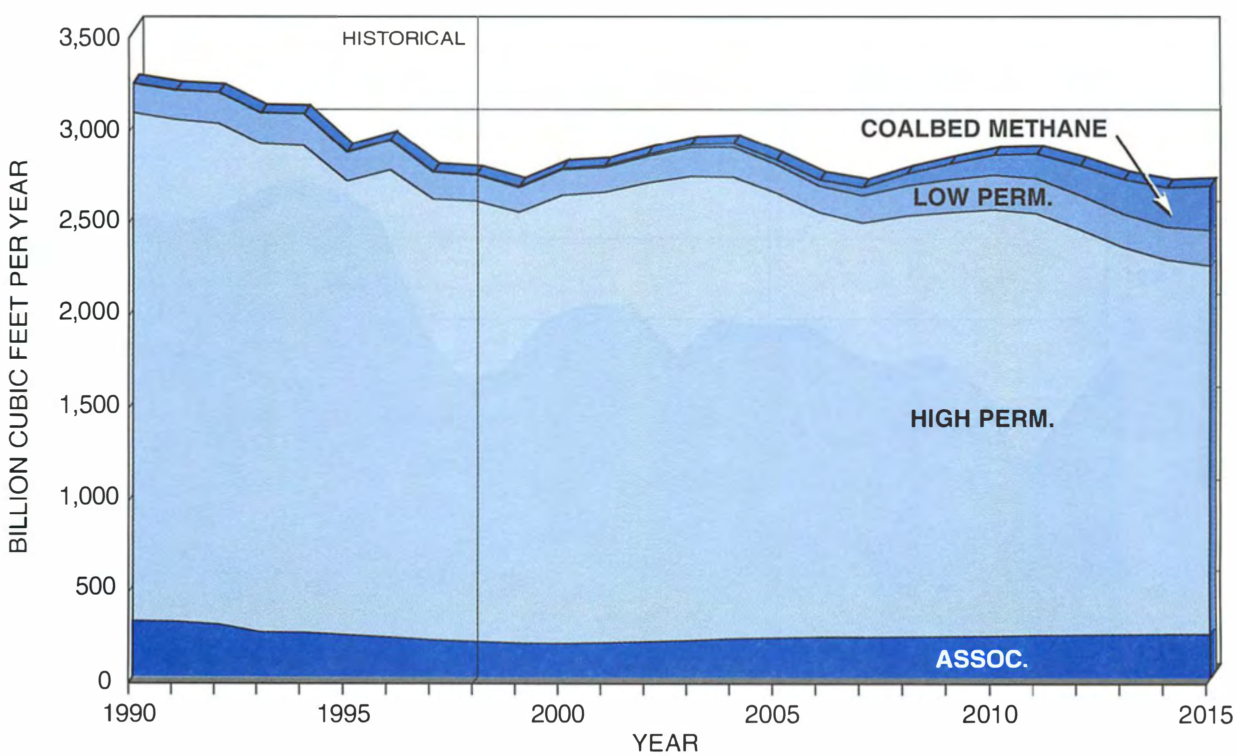
Proved Reserves	Old Field Appreciation	New Fields	Coalbed Methane	Tight Gas	Total Assessed Additional Resources	Total Cumulative Production	Total All-Time Recovery
	Assessed Additional Resources						
25,942	48,430	39,675	7,449	16,923	112,477	181,445	319,864

TABLE S-31

MID-CONTINENT GAS PRODUCTION

Year	2005	2010	2015
Annual Production	2.8 TCF	2.7 TCF (0.7%/yr decline)	2.6 TCF (0.7%/yr decline)
% of U.S. Production	12.4%	10.9%	9.6%

Figure S-48. Mid-Continent Gas Production



The region is characterized by numerous play types, with hydrocarbons occurring from extremely shallow plays through 25,000+ foot sediments. The Mid-Continent Region also enjoys a regulatory climate that favors the exploration and production industry. Infrastructure is well established and extensive, suggesting that the ability of the region to meet expectations is limited only by the resource. Figure S-49 shows projected gas well completions through 2015.

As a result of existing high well density in the region, the per-well contribution to the projected production is modest, estimated at 0.5–1.0 BCF per conventional gas well (Figure S-50).

A continued emphasis on marginally profitable oil projects and multi-well drilling programs is projected to result in a 75% increase in drilling projects—from close to 4,000 wells/year currently to over 7,000 wells/year ten years from now. Investment decisions are expected to generate a steady increase to the 5,000 wells/year level by the 2004–2006 period, and a subsequent rapid escalation in drilling activity to the 7,000 wells/year level by 2010. Roughly one-third of the wells drilled are gas wells, and only a small fraction of these target tight gas reservoirs or coalbed methane accumulations, with a commensurately small but increasing contribution from these resources.

High permeability non-associated gas will continue to dominate regional production. While the contribution of associated gas, coalbed methane, and tight gas reservoirs does increase over time, it is not projected to represent more than 20% of production. Associated gas, now making up 60% of this 20%, rises only slightly, eventually becoming less significant (less than 40%) in terms of the "mix" not attributable to conventional, higher-permeability gas reservoirs.

The implications of these model results, however, are challenging. The data suggest renewed emphasis on all oil and gas resource projects in the region. While individually these projects are likely to offer only marginal production and modest economic expectations, their combined contribution will be significant. It is the relatively low implied risk that drives these projects. Numerous projects that focus on in-field development are expected to support continued growth in existing fields. A

Figure S-49. Historical and Projected Gas Wells in Mid-Continent Region

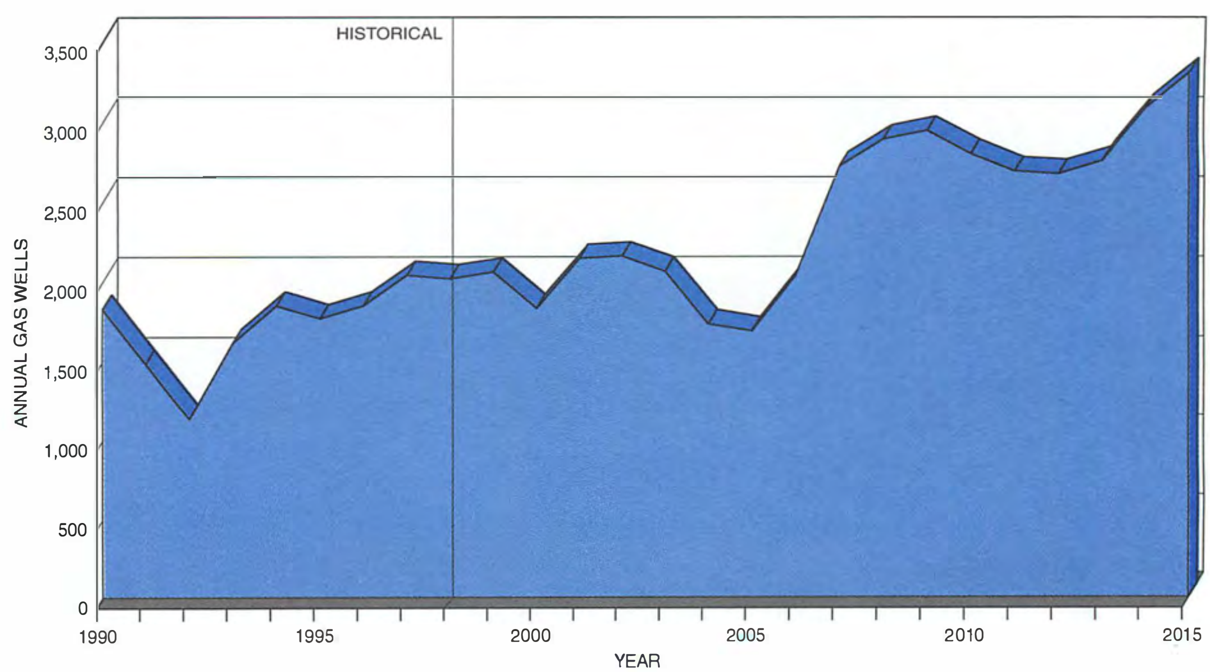
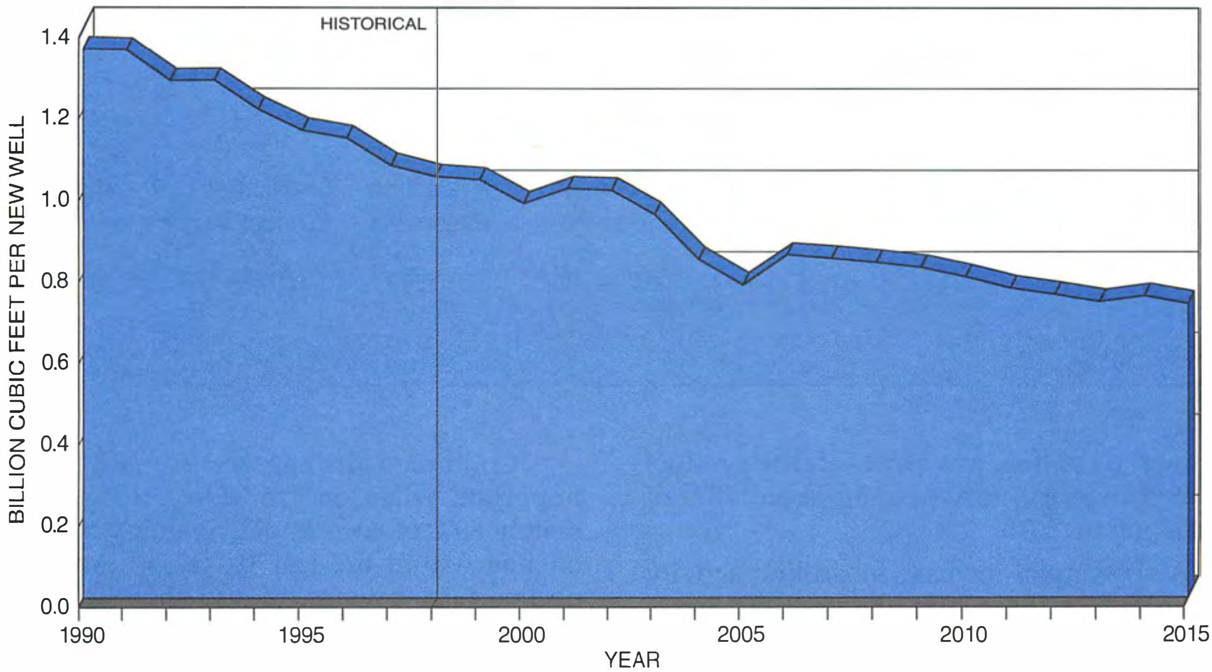


Figure S-50. Historical and Projected Gas Well Recovery in Mid-Continent Region



"higher risk" component of the Mid-Continent picture is the 40 TCF associated with currently undiscovered accumulations. Most of this resource base is assessed in extremely deep accumulations. Historical drilling projects have tested many of the obvious large structures that exist at depth, especially in the Anadarko Basin. This resource is extremely challenging to exploit, but with significant advances in extraction technology may be demonstrated within the forecast period.

Texas Gulf Coast Onshore

The Texas Gulf Coast Onshore continues to be an important natural gas supply source. Resource estimates are shown in Table S-32. Remaining proved reserves are estimated to be 14.9 TCF or 9.5% of remaining U.S. reserves. The region has cumulative production of 140.5 TCF or approximately 15.9% of total U.S. natural gas production to date. Estimated Total Remaining Resources are 130.9 TCF, or 8.9% of the total U.S. resource base. Current production from this region is about 210 BCF per month.

The 1992 Study predicted that the Texas Gulf Coast Onshore would experience continued production decline. However, gas production has increased substantially. The region continues to experience both New Field discoveries and low permeability development. The single most important aspect of increased activity since the 1992 Study has been the development of the Wilcox Lobo trend.

The New Field resource base was estimated by updating the assessment of the 1992 Study. The estimated original in-place hydrocarbon field size distribution was determined. Discovered fields were ranked by field size and subtracted from the total to arrive at a remaining New Field resource base. Low permeability resources were also evaluated.

In the projection (see Figure S-51), high permeability reservoirs are expected to continue to provide the majority of production through 2015, and high permeability production will increase over the long term. In 1998, high permeability non-associated gas represented about 70% of production. While associated-dissolved gas production is projected to

TABLE S-32

TEXAS GULF COAST ONSHORE RESOURCES
(Billion Cubic Feet)

	Assessed Additional Resources						
Proved Reserves	Old Field Appreciation	New Fields	Tight Gas	Total Assessed Additional Resources	Total Remaining Resources	Cumulative Production	Total All-Time Recovery
14,858	54,341	52,550	9,114	116,005	130,863	140,468	271,331

continue to decline, low permeability production will increase, representing about 28% of production by 2015.

A substantial increase in drilling activity is projected for the region. Figure S-52 shows the level of total well completion activity that is necessary to meet the above production projection.

Continued drilling activity is extremely important when one considers that approximately 80% of current deliverability has come on line within the last 10 years. Analyzing decline rates by vintage also shows that new supplies are declining at a higher rate than older vintages, 17% per year versus 10%. This increase in decline rate is due primarily to

Figure S-51. Texas Gulf Coast Onshore Gas Production

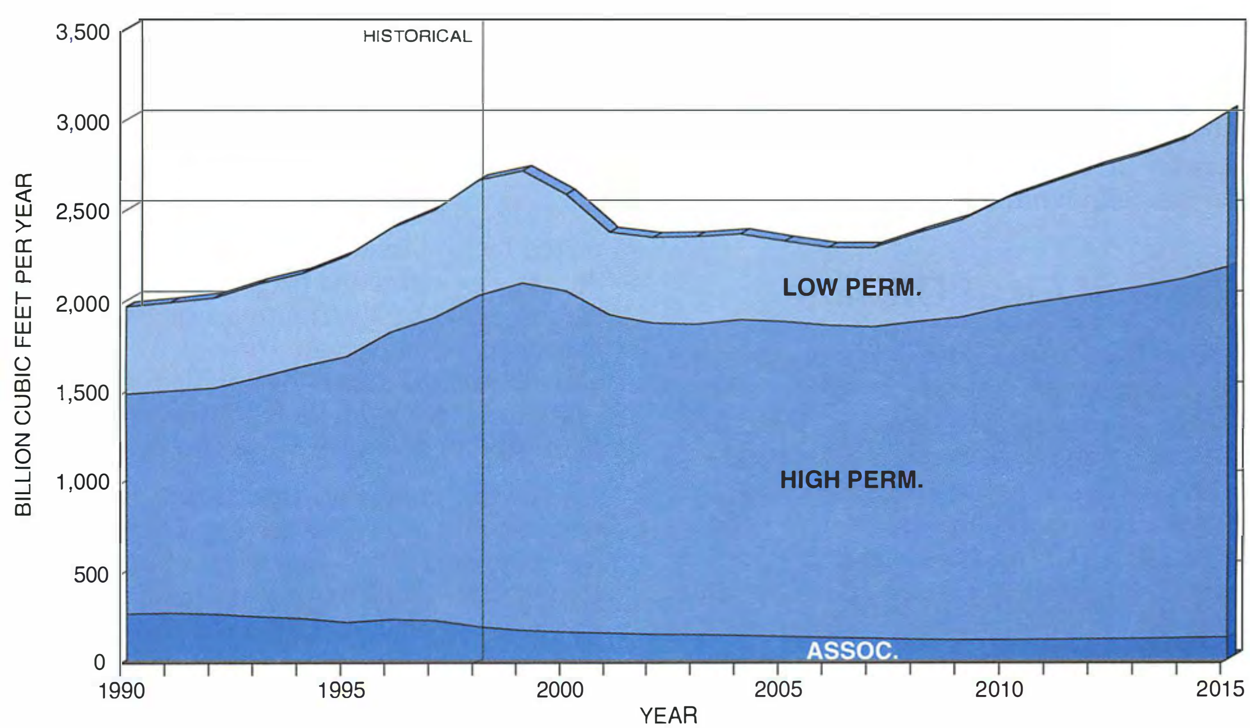
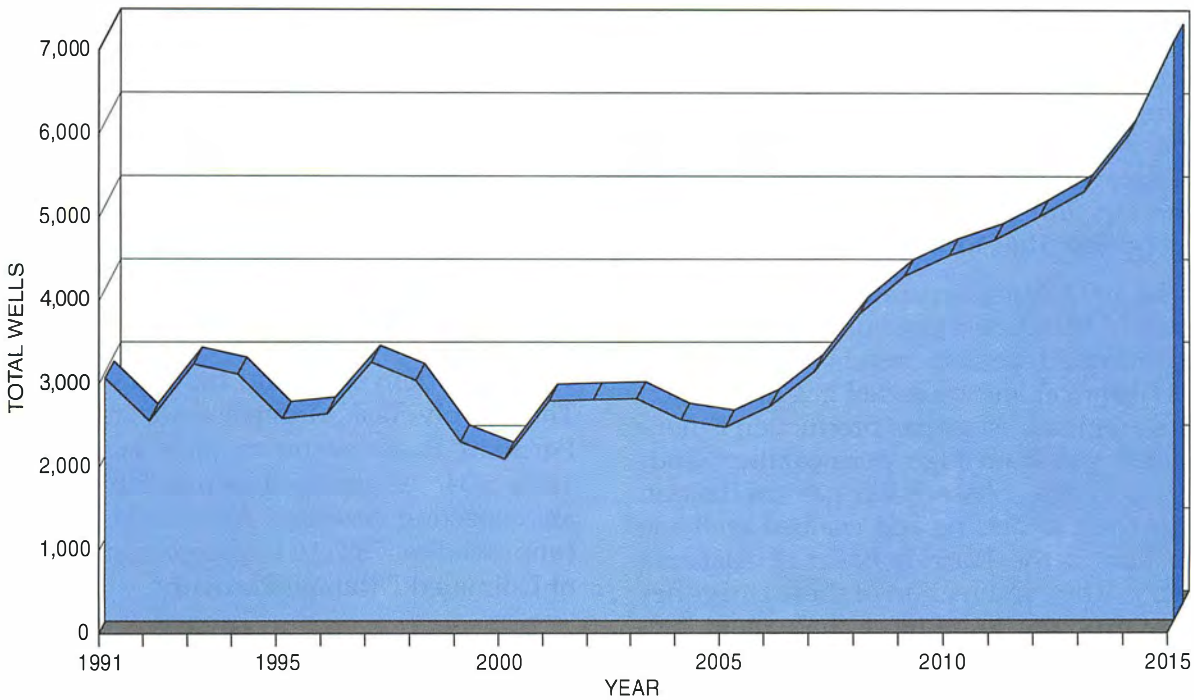


Figure S-52. Annual Oil and Gas Well Completions, Texas Gulf Coast Onshore



smaller reservoirs being completed with better, more-efficient completion procedures.

Eastern Gulf Coast Onshore

The Eastern Gulf Coast Onshore is defined geographically as onshore South Louisiana, Alabama, Mississippi, and Florida. Resource estimates are shown in Table S-33. Remaining proved reserves are estimated to be 7.8 TCF or 5.0% of remaining U.S. reserves. These regions have cumulative production of 111.9 TCF or approximately 12.7% of total U.S. natural gas production to date. Estimated Total Remaining Resources are 58.9 TCF, or 4.0% of the total U.S. resource base. Current

TABLE S-33

EASTERN GULF COAST ONSHORE RESOURCES (Billion Cubic Feet)

	Proved Reserves	Old Field Apprecia-tion	New Fields	Coalbed Methane	Total Assessed Additional Resources	Total Remaining Resources	Cumulative Production	Total All-Time Recovery
MS, AL, FL	1,955	5,069	8,674	5,209	18,952	20,907	12,756	33,663
S. LA	5,855	20,361	11,838	0	32,199	38,054	99,127	137,181
Total	**7,810**	**25,430**	**20,512**	**5,209**	**51,151**	**58,961**	**111,883**	**170,844**

production from this region is about 100 BCF per month.

The resource base was estimated by evaluating the original in-place hydrocarbon field distribution from the 1992 Study, and subtracting the discovered fields. Coalbed methane resources were also assessed. In recent years, these regions have been more impacted by Old Field Reserve Appreciation than by New Field discoveries. Fields tend to be multi-pay and highly faulted in character, which provides opportunities for reserve appreciation.

The 1992 Study accurately predicted that the Eastern Gulf Coast Onshore would experience continued decline trends. Figure S-53 shows historical and projected gas production for these regions. Most gas production is non-associated gas from high permeability sandstone reservoirs. Associated gas production will continue to decline and coalbed methane production in the Warrior Basin of Alabama will vary. The combination of these categories is never expected to be more than about 20% of the region's production.

Analysis of Figure S-54 reveals the importance of continued drilling activity to maintain deliverability in this region. Approximately 70% of current deliverability has come on line within the last 10 years. Analyzing decline rates by vintage also shows new supplies are declining at a higher rate than older vintages, 18% per year versus 10%. This increase in decline rate is due primarily to smaller reservoirs being completed with better, more efficient completion procedures.

Permian Basin

The Permian Basin is considered to be a mature producing province at shallow depths and in the oil-prone areas. However, it has very important deep and tight gas resources. The Supply Task Group's assessment of the Permian Basin resource base is shown in Table S-34. As can been seen in Table S-34, we are expecting Assessed Additional Resources (unproved) of 73.2 TCF or approximately 73% of Estimated Ultimate Recovery.

As is shown in Figure S-55, we are projecting Permian Basin production of about 1,500 BCF per year until approximately 2010. At about this time, the model output indicates

Figure S-53. Eastern Gulf Coast Onshore Gas Production

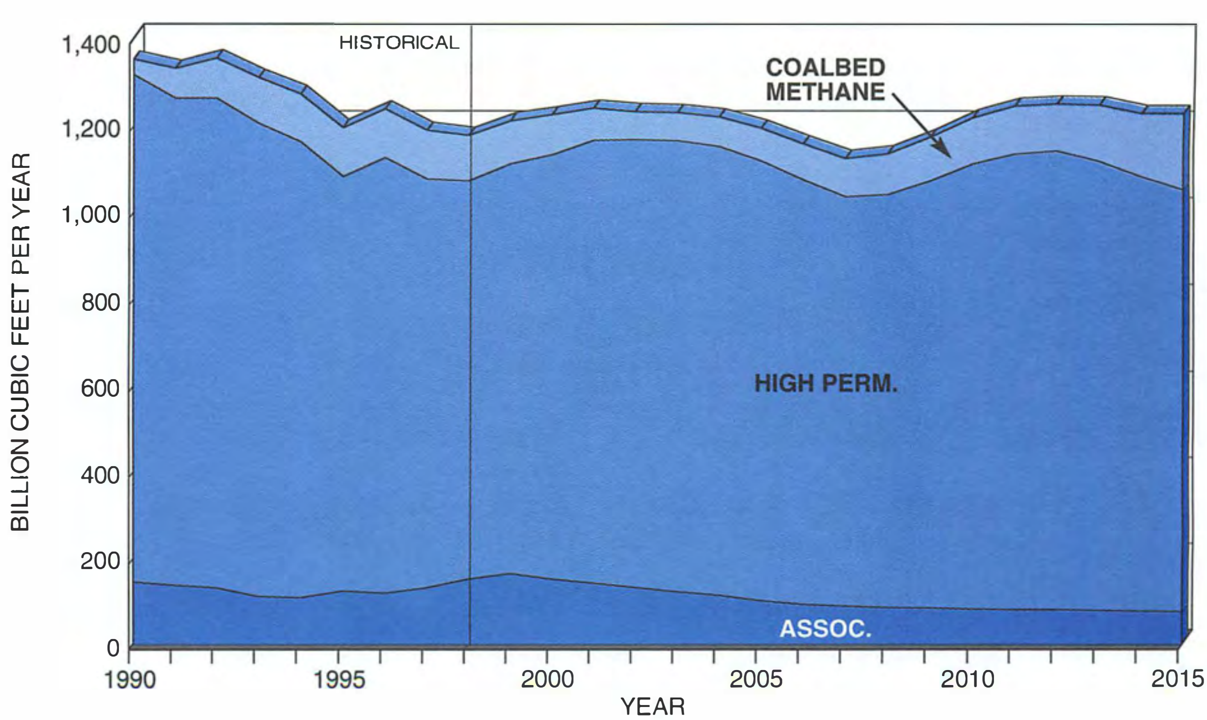


Figure S-54. Annual Oil and Gas Well Completions,
Eastern Gulf Coast Onshore

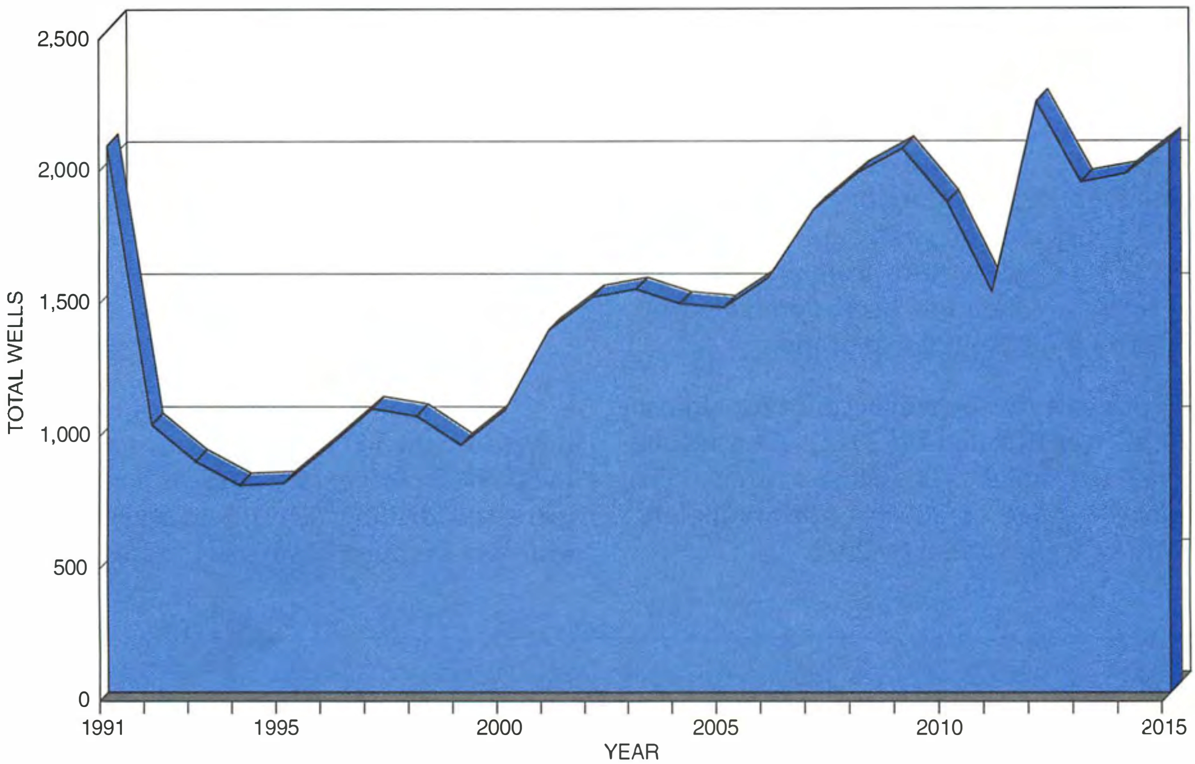


TABLE S-34

PERMIAN BASIN RESOURCES
(Billion Cubic Feet)

Proved Reserves	Assessed Additional Resources: Old Field Appreciation	New Fields	Tight Gas	Total Assessed Additional Resources	Cumulative Production	Total All-Time Recovery
12,293	22,319	31,353	19,521	73,193	87,976	173,462

an increase in production due to increased exploratory drilling related to a combination of two factors:

- Evolution of technology, which results in an improved ability to exploit deeper reservoirs whose characteristics are very challenging under current technology.
- Projected higher prices (both oil and gas), which result in improved project economics, justifying the higher risk profile.

This combination of factors results in the higher gas production from deeper reservoirs (which will be more gas prone versus oil). The projection of drilling activity is shown in Figure S-56. Drilling activity will slightly exceed the recent peak seen in 1997. Although the Permian Basin will still be primarily an "oil play," the mix of hydrocarbon targets will change somewhat. Because of the factors noted above, price incentives, and technological improvements, exploratory activities will have a significant increase. As Figure S-57 shows, this is a departure from the region's recent history, which has been dominated by exploitation with limited exploration.

Exploratory wells will account for almost half of all wells drilled by 2012. As a result, projected dry holes will increase from their historical average of 20% to approximately one-third of wells drilled by 2012.

Our analysis is projecting an increase in tight gas completions, commencing in approximately 2007, as shown in Figure S-58.

As a result of higher demand and prices and facilitated by technological advances, denser well spacing is anticipated in the following tight gas areas of the Permian Basin:

- Canyon Sand (Southeast Permian Basin, near Ozona and Sonora, Texas)
- Abo (Southeast New Mexico)
- Morrow (Southeast New Mexico).

Tight gas production is projected to increase from 300 BCF per year as of 2006 and to 500 BCF per year by 2015, as a result of the increased drilling activity, to a level of one-fourth of Permian Basin gas production.

Figure S-55. Permian Basin Gas Production

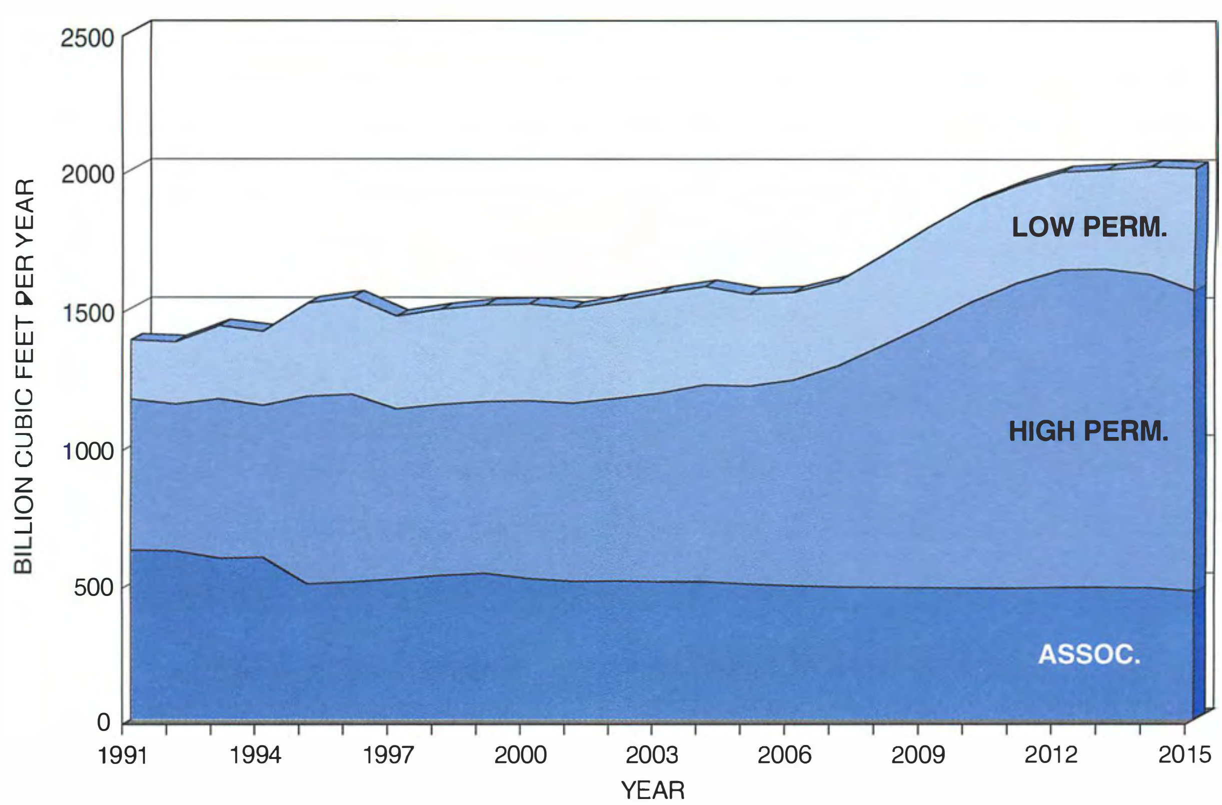


Figure S-56. Permian Basin Drilling Projection

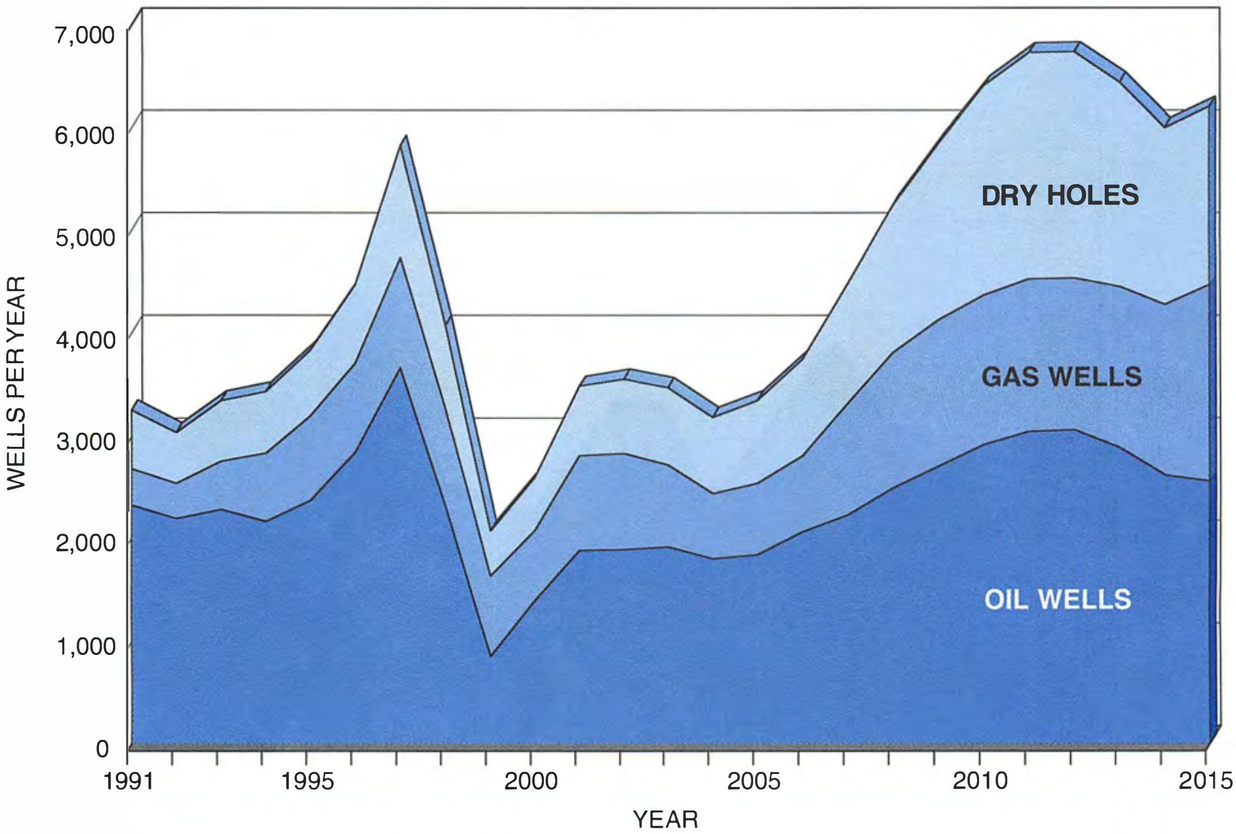


Figure S-57. Permian Basin Exploratory Activity

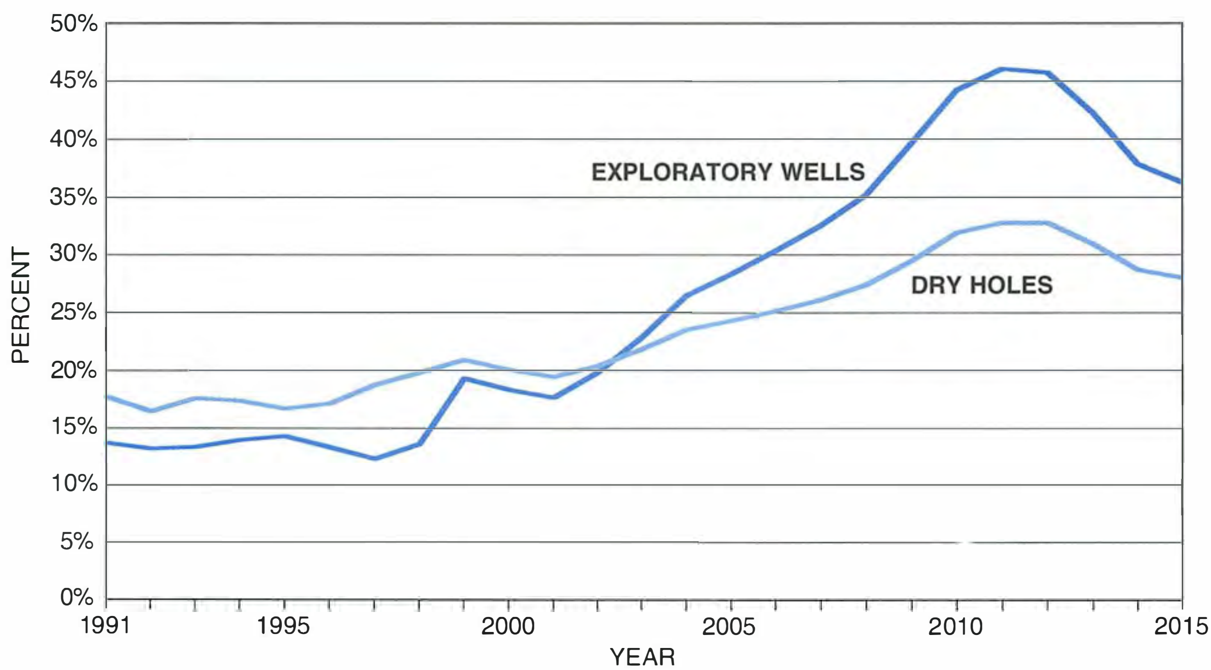
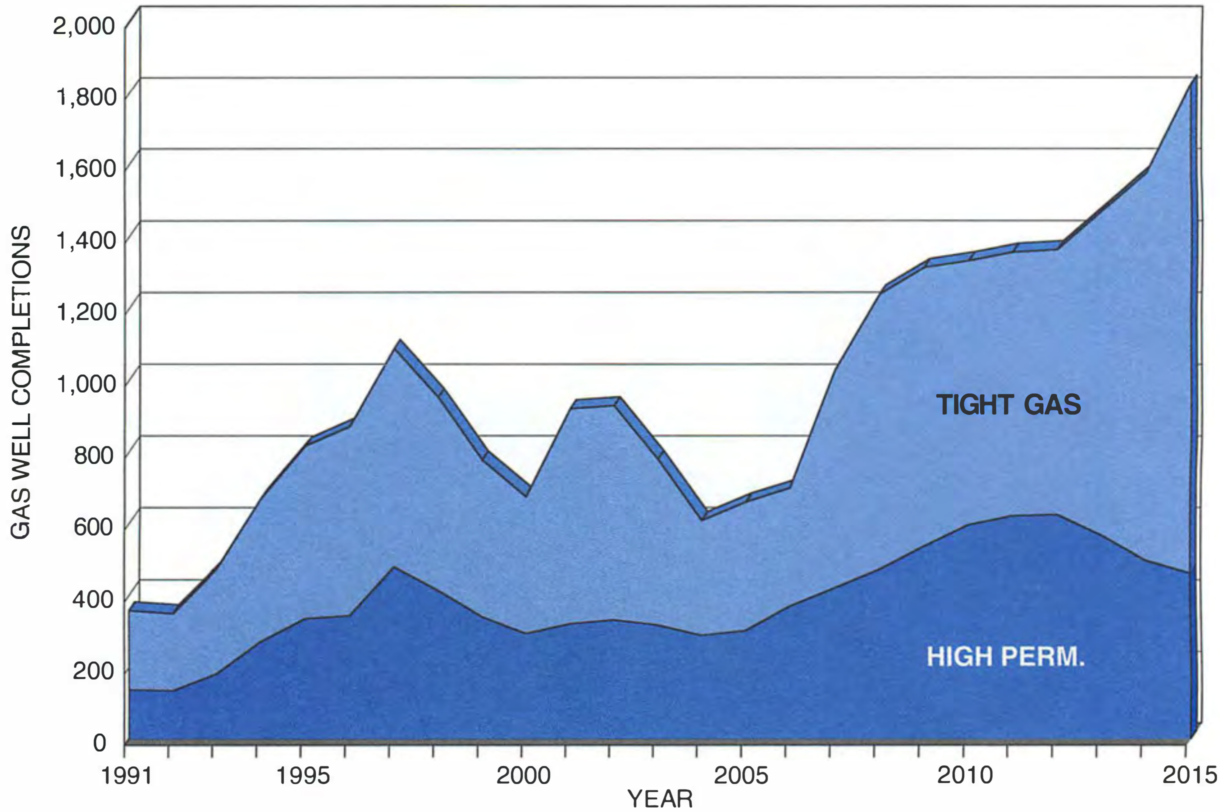


Figure S-58. Permian Basin Gas Well Completion Projections



Chapter Seven

Determination of Model Inputs

The GRI Hydrocarbon Supply Model (HSM) was used to investigate gas supply issues for National Petroleum Council's 1992 Study on Natural Gas and was chosen again for this study. The HSM was developed by Energy and Environmental Analysis, Inc. (EEA) for the Gas Research Institute (GRI) in the early 1980s and has undergone continuous updates and improvements since then. The HSM is a PC-based analytical framework designed for the simulation, forecasting, and analysis of natural gas, crude oil, and natural gas liquids supply, and for cost trends in the United States and Canada. It is a process-engineering model with a very detailed representation of potential gas resources and the technologies with which those resources can be proved and produced. The degree and timing by which resources are proved and produced are determined in the model through discounted cashflow analyses of alternative investment options and behavioral assumptions in the form of inertial and cashflow constraints and the logic for setting producers' market expectations (e.g., future gas prices).

The model covers the lower-48 United States, Alaska, and Canada. The lower-48 states are broken down into thirteen onshore regions and four offshore regions (see Figure S-1 in Chapter One of this Supply Task Group Report). The onshore regions in the model are divided into four depth intervals: 0-5,000 feet, 5-10,000 feet, 10-15,000 feet, and below 15,000 feet. The offshore regions are divided into up to eight water depths or areas. Each depth interval within each region is modeled with a unique resource base, exploratory find rates, drilling costs, and well production profiles. Canada is divided into five regions, which are further divided into intervals representing drilling depths or subregional areas. Resources in the HSM are divided into three general categories: Old Field Reserve Appreciation, New Fields, and Nonconventional Gas. Table S-35 summarizes the gas resource assessment of the 1999 Study, and compares it to the 1992 Study. Both current and advanced technology resources are shown. Characterization of each category of resource as well as other model inputs are discussed below.

Old Field Reserve Appreciation

Reserves in a field are proved over a period of several years. For this reason, only a portion of the gas reserves in fields found by a New Field drilling increment undertaken in a year will be proved and available for production in that year. The remaining reserves will be proved in later years. The HSM maintains inventories of potential resources that can be proved from already discovered fields. This resource is commonly referred to as "Old Field Reserve Appreciation." As the model simulation proceeds, these Old Field Reserve Appreciation inventories are drawn down as

TABLE S-35

COMPARISON OF ALL-TIME GAS RECOVERY ASSESSMENTS
1999 VS. 1992 NPC STUDIES
(Trillion Cubic Feet of Total Gas)

	1992 NPC Study (1-1-91) "Base" Tech	1999 NPC Study (1-1-98) Current Tech	1992 NPC Study (1-1-91) Advanced Tech	1999 NPC Study (1-1-98) Advanced Tech
LOWER–48 STATES				
Cumulative Production	758	881	758	881
Proved Reserves	160	157	160	157
Ultimate Recovery	918	1,038	918	1,038
Old Field Reserve Appreciation	215	305	236	305
New Fields	429	573	493	633
Nonconventional	263	289	406	371
Assessed Additional Resources	907	1,167	1,135	1,309
Total Remaining Resources	1,067	1,324	1,295	1,466
All-Time Recovery	**1,825**	**2,205**	**2,053**	**2,347**
CANADA				
Cumulative Production	65	103	65	103
Proved Reserves	72	64	72	64
Ultimate Recovery	137	167	137	167
Old Field Reserve Appreciation	22	22	24	22
Discovered Undeveloped	47	35	47	35
New Fields	345	346	379	384
Nonconventional	135	126	218	162
Assessed Additional Resources	549	529	668	603
Total Remaining Resources	621	593	740	667
All-Time Recovery	**686**	**696**	**805**	**770**

the resources are proved. At the same time, the appreciation inventories are increased from future year appreciation to New Fields discovered during the model simulation.

One of the assumptions the user of the HSM must make is the size of the Old Field Reserve Appreciation potential as of some recent year. For the 1992 Study, an extensive statistical analysis was made of historical field growth histories to estimate the Old Field Reserve Appreciation potential as of 1989. This analysis was revised extensively to update those assumptions for the 1999 Study.

NPC Assessment of Old Field Reserve Appreciation

The term used to describe the sum of an oil or gas field's Cumulative Production plus Proved Reserves is Estimated Ultimate Recovery (EUR). Data on EUR by year of field discovery have been published by the American Petroleum Institute (API) and the American Gas Association (AGA) from 1966 to 1979 and by the EIA from 1977 to the present. Since the data were first published, EUR for most oil and gas fields has consistently increased over time. The estimate of additional future increases in a field's reserves is Old Field Reserve Appreciation. Old Field Reserve Appreciation occurs as a result of field extensions and new reservoirs, positive revisions resulting from infill drilling, technology leading to improved recoveries, recompletions, and workovers, lower abandonment pressures, and improved economics leading to lower abandonment rates.

Much Old Field Reserve Appreciation is a function of how well the physical parameters of the reservoir can be understood and utilized as a basis to target new well completions. Increasingly sophisticated technologies ranging from 3D seismic, horizontal drilling, cased and open-hole logging, and computer visualization/simulation have allowed progressively improved characterization of reservoirs and their heterogeneities. True Old Field Reserve Appreciation occurs when hydrocarbons that are not in flow communication with existing wellbores are accessed, or when existing non-economic flow rates improve and become economic. Old Field Reserve Appreciation should not be confused with rate acceleration.

The basis for all Old Field Reserve Appreciation is that reservoirs are not uniform tank-like rock volumes whose pore space is filled with hydrocarbons. The nature of the reservoir varies laterally and vertically based on the depositional system that formed the accumulated rock volume, and on post-depositional events like faulting and cementation of pore space. The greater the geologic variability in the reservoir, the more heterogeneous the reservoir is likely to be, leading to greater compartmentalization of the hydrocarbon-bearing pore space. The better these internal heterogeneities can be described through the process of reservoir characterization, the more the remaining resource can be targeted and produced. Because understanding of any given reservoir, field, or group of fields improves as more wells are drilled, and because technology improves over time, reserve appreciation is sensitive to both cumulative drilling and time. Reserve appreciation algorithms have used one or both of these parameters as part of their assessment methodologies.

Some of the technologies applicable to natural gas reserve appreciation were reviewed in the 1992 Study. All of these technologies remain applicable to natural gas reserve appreciation and include improvements in well logging, well stimulation, methods of reservoir engineering diagnosis, and seismic acquisition and interpretation. Well logging continues to improve, resulting in the ability to evaluate low resistivity contrast pay zones in the open-hole environment. Cased-hole resistivity logging is near or at commercial reality. Well stimulation, especially diagnostics for hydraulic fracturing, have improved in the last five years, leading to lower costs and more effective well clean-up after fracturing. 3D seismic processing and interpretation capabilities using computer workstations have allowed vastly improved imaging of reservoir compartmentalization. Using many new software products, geophysical images can be combined with geologic and engineering data to help visualize what parts of the reservoir have been produced and where remaining hydrocarbons may be trapped. Mention should also be made of improvements in deviated and horizontal drilling capability. Considerable experience has been gained with this technology with the result that more extended-reach wells have been drilled and successfully completed.

Previously published estimates for the growth of existing proved reserves were made on a subjective basis or they were based upon a statistical analysis of past history (i.e., how reserves are added to fields as a function of time). The statistical relationship of how reserves are added through time is commonly referred to as a "growth curve." In the 1992 Study, a new technique was developed to estimate a lower-48 reserve growth curve as a function of both time and total lower-48 gas drilling activity. Reserve growth potential of non-associated gas in each region was calculated by applying the growth curves to fields in each region. Likewise, oil field growth was estimated as a function of time and lower-48 oil well drilling activity, and that curve was applied to oil fields to estimate regional appreciation potential of crude oil and associated-dissolved gas.

Because reserve growth is such a significant part of the overall resource base, it was determined that the 1999 Study should build on the work of the 1992 Study by performing more region-specific statistical analyses. The approach selected at the beginning of the 1999 Study was to match annual EUR derived from EIA Form 23 with gas well drilling activity from the PI/Dwights gas well reports. Those data were then used to estimate growth curves for each field vintage (i.e., all fields found in one year) within a region as a function of time and the number of wells drilled in those fields. The Dallas Field Office of EIA using confidential information contained in the Form 23 reserve reports performed this work.

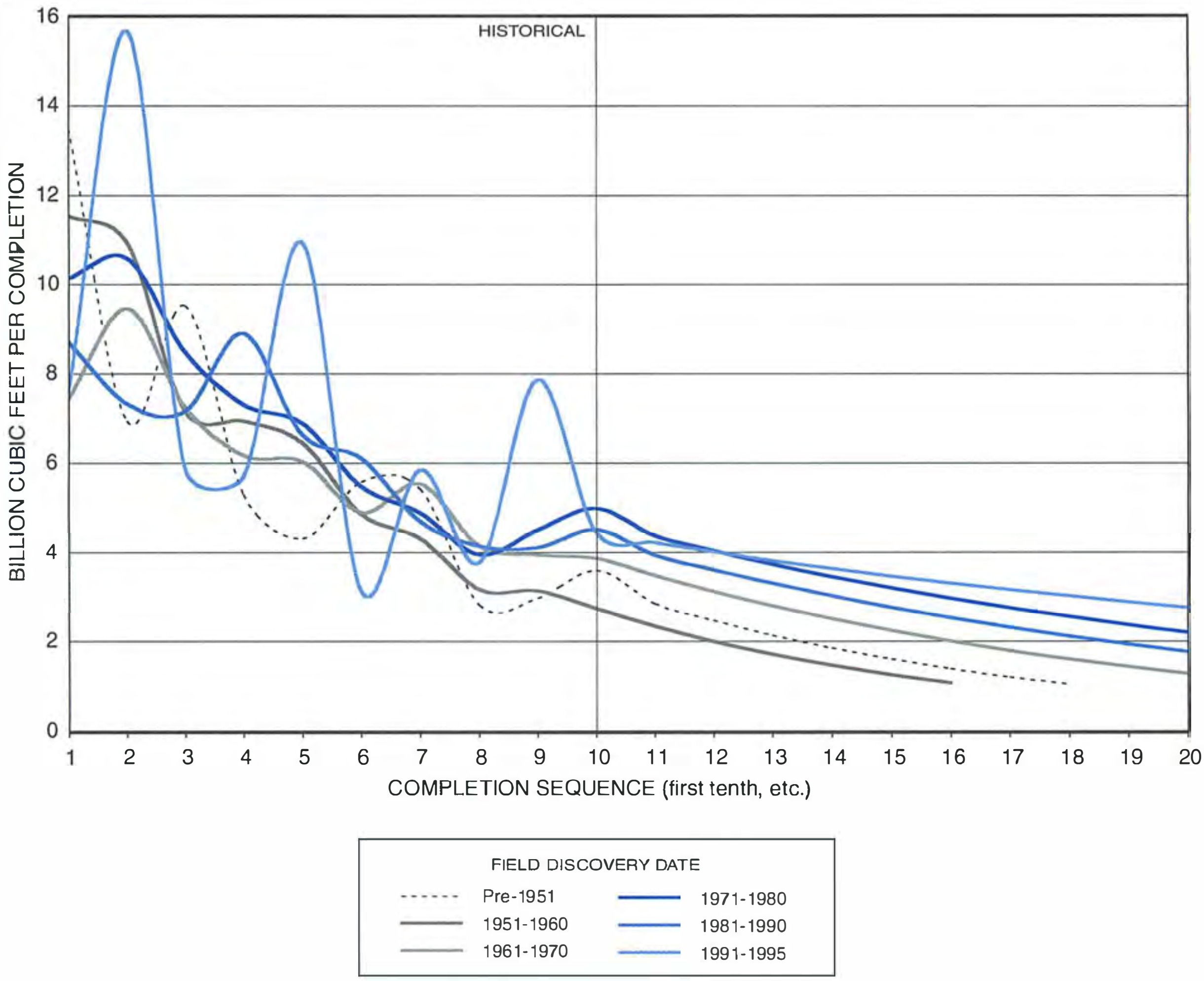
Because of the long time needed to prepare the EIA data for all regions of key interest, EEA conducted a second, less data-intensive approach for input into the Reference Case. This second approach updated an EEA analysis conducted for the Gas Research Institute in 1993 based on the observation that successive increments of drilling in fields of a certain age show declining EURs. By extrapolating those declining per-completion recoveries, it is possible to estimate how many reserves could be added by additional gas completions and, thus, the appreciation potential of the fields. For this analysis, EEA estimated ultimate recoveries of each gas completion using PI/Dwights gas well reports. EEA fit a statistical curve over the historical data and projected what the ultimate recoveries would be for hypothetical future completions. Future completions were assumed to be no longer economically feasible when their productivity fell below a minimum threshold based on drilling depth for onshore regions and water depth for offshore regions. The non-associated gas reserve growth potential was the number of wells in each increment of completions times their estimated ultimate recovery summed across all increments that could be made before the threshold were reached.

Figure S-59 illustrates what the data look like for the Gulf of Mexico shelf. The historical drilling data for each field vintage were divided into 10 equal-size groups of completions. The groups numbered 11 and higher represent hypothetical future increments of drilling for which recovery per completion is estimated as a statistical extrapolation from the 10 historical groups. The reserve appreciation potential is calculated as the number of completions in each group times the average recovery per completion. For the offshore shelf, the future groups of completions are deemed impractical when their productivity falls below one BCF per completion.

Table S-36 illustrates expected Old Field Reserve Appreciation as of January 1, 1998 by region developed using EEA's analysis of decline in EUR per completion. A comparison to the 1992 Study Old Field Reserve Appreciation estimates is also shown.

Old Field Reserve Appreciation values are generally higher than those of the 1992 Study even though the date of the assessment is seven years later. One reason for the higher Old Field Reserve Appreciation also applies to other categories that contributed to an overall increased Total Resource in the 1999 Study—changes in statistical technique and definition of what resources are being counted. The 1999 Study uses growth statistics specific to each region, drilling depth, and field vintage versus a more generalized growth curve applied in the 1992 Study. Another difference is that the 1999 Study uses an explicit BCF-per-completion volumetric cut-off point to define economic thresholds for wells in a given region whereas the 1992 Study applied

Figure S-59. Recovery per Gas Completion by Field Vintage, Gulf of Mexico Shelf



a maximum age at which the generalized lower-48 growth curve was assumed to end.

The results of the 1999 Study were verified by comparing the results of the decline in EUR per completion method with the statistical technique developed using EIA Form 23 data. In the regions where comparisons could be made, the results were deemed to be very similar. These comparisons are shown in Appendix K.

In conclusion, new resources continue to be found and developed in existing fields, and are a major component of the nation's reserve inventory. As technology develops, reservoir characterization is improved, leading to a better understanding of reservoir systems and economic development and production of these resources.

New Fields

The HSM uses resource base estimates, exploratory finding rates, drilling costs, and well production profiles to describe the operational nature of the exploration and production (E&P) activities of both oil and gas. This approach captures the complexity of the process and allows the distinction between exploratory and economic success.

The central element in the supply modeling procedure is the estimate and distribution of the undiscovered New Field gas resources available for exploration and subsequent development. Each region and depth is described with its own unique exploration finding rate and field size distribution, which in turn defines the resource estimate. The conventional undiscovered resource includes

TABLE S-36

ESTIMATES OF OLD FIELD RESERVE APPRECIATION
LOWER-48 STATES AND CANADA BY REGION
(Billion Cubic Feet; Technically Recoverable)

Region*		1992 NPC Study† (as of 1/1/91)	1999 NPC Study (as of 1/1/98)
A	Appalachia	1,642	2,301
B	Eastern Gulf Onshore	5,128	5,069
C	North Central	2,920	2,718
D	Arkla – East Texas	14,818	25,864
E	South Louisiana	21,535	20,361
G	Texas Gulf Onshore	36,242	54,341
WL	Williston Basin	1,153	2,653
FR	Rocky Mtn. Foreland	11,570	28,949
SJB	San Juan Basin	7,647	11,673
OV	Overthrust Belt	8,327	702
JN	Mid-Continent	33,637	48,430
JS	Permian Basin	23,078	22,319
L	West Coast Onshore	3,138	5,717
BO	Eastern Gulf of Mexico	3,555	2,160
EGO	Central & Western Gulf of Mexico	61,159	70,661
LO	West Coast Offshore	765	1,039
AO	Atlantic Offshore	0	0
Total Lower-48 States		**236,314**	**304,957**
ASM	Alberta, Saskatchewan, Manitoba	20,800	18,620
BC	British Columbia	2,700	3,283
NWC	Northwest Canada	0	0
EC	Eastern Canada	300	478
ART	Arctic Canada	0	0
Total Canada		**23,800**	**22,381**

*See Figure S-1 for map of regions.

†Old Field Reserve Appreciation from the 1992 Study reflects re-allocation of certain resources among categories consistent with the 1999 Study.

resources in undiscovered fields in both known and speculative plays. Known plays are those in which discoveries have been made. Speculative plays usually have a strong conceptual basis but no actual discoveries, and include areas that have very little seismic coverage or drilling data.

The New Field conventional resource in the model is uniquely described for each cell (region and depth) by an exploration finding rate for each field size class. Within each cell, there are 20 field size classes ranging from about 4,000 barrels of oil equivalent (BOE) to greater than 2 billion BOE. Each size class is twice the size of the next smaller class. When available, historical drilling and production data from a number of sources are utilized to define the characteristics (largest field, number and rank of fields, shape of the distribution, etc.) of the field size distributions and finding rates. In frontier areas, the field size distributions are developed from geologic analogies.

The exploration process in an area rapidly increases geologic "knowledge" by condemning some parts of an area as nonprospective and identifying others as having high potential. During the early exploration of an area, many of the very large fields are found simply because they have the highest probability of being encountered by virtue of their areal extent. As exploratory drilling progresses, it tends to be concentrated in known productive areas where smaller fields are targeted, thus leading to an increase in the number of fields discovered per unit of exploration activity. However, the number of fields of a given size per unit of activity decreases with time.

The Arps-Roberts equation was developed in 1958 to describe the phenomenon that a decreasing number of fields of a given size will be found per unit of exploration and this equation yields an exponential decline in the rate at which all field size classes are found. However, historical data indicate that while this may be true for large fields, small to medium fields are found in greater numbers than predicted by Arps-Roberts. To adequately model the number of small fields found per unit of activity, the HSM employs a modified Arps-Roberts find rate equation called the double-exponential equation. This formulation adds a term to the Arps-Roberts equation to account for the concentration over time of drilling in known areas, targeting of smaller fields, and the learning curve from exploratory drilling.

Although gas is the focus of this study, the HSM simulates the exploration process for total hydrocarbons. Because oil and gas usually occur in similar geologic settings, their exploration, development, and production histories are necessarily intertwined. The model explores for hydrocarbons and once they are found, allocates them to oil and non-associated gas. The user-specified relative occurrence of gas to oil for each region and depth interval forms the basis for a split of discovered hydrocarbons between oil and gas. Associated and dissolved gas and natural gas liquids are determined from ratios applied to the discovered oil and non-associated gas volumes.

The model makes a further distinction between high and low permeability gas. Low permeability gas is generally defined as that gas occurring in formations with a permeability of less than 0.1 millidarcy. The historical record includes many instances of fields being exploited that are, under this definition, low permeability gas. Thus, undiscovered low permeability fields in these areas are described in the finding rate equations and field size distributions developed from the analysis of the historical record. Consequently, the amount of non-associated gas discovered by the model is split between high permeability and low permeability gas once exploration has been done. Other accumulations of low permeability gas that have no production history are represented in the Enhanced Recovery Module part of the model.

The HSM exploration process predicts the number of fields of each size class (in each depth interval) found by an increment of exploratory well drilling. Each of the field sizes is described for development purposes by the number of wells required for full development, the costs for wells and facilities, and the rate at which the ultimate size of the field will be booked as proved reserves. The HSM books the reserves of the smallest fields in one year and progressively uses longer booking schedules for larger field sizes, with the largest fields scheduled over 30 years.

Once the results of an exploratory program are determined, an economic analysis of each of the field sizes using all of the aforementioned parameters is utilized to determine which of the fields are economic for development. The overall economics of the exploration program are then evaluated to determine if they provide an acceptably attractive investment opportunity; if not, the exploration program is deferred.

After a field is "discovered," the model simulates the process by which reserves are developed in the field over time. The number of wells required for field development is largely predicated on field area and volume. The largest fields have the highest recoveries per well but still require the most wells for full development. Historical data on number of wells drilled in fields of a specific size class, average recovery per well, and cost components are utilized to model drilling requirements for fields in each region and depth interval.

In the model, gas fields are treated differently than oil fields in that, once production capacity is installed, production does not necessarily proceed at the maximum sustainable rate. Because of this, what would normally be treated as a production profile for oil is referred to as a deliverability (potential production) profile for gas. These profiles are part of the data that determine the revenues a producer can expect from field development. In brief, a deliverability profile is generated for each well in a block of reserves proved in each year after the field is discovered. This produces a series of production-from-reserves curves for each year after discovery. The profiles for the blocks of reserves are then summed to a field total. Thus, the annual field production, cumulative field production, and cumulative reserve additions can be modeled for each field.

NPC Assessment of New Field Resources

The 1992 assessment of the size of the undiscovered resource was done by a consensus approach, initially involving a small core group of industry, government, and association representatives. This core group first developed a working understanding of the HSM, including not only how the model uses the resource base but also what criteria define the resource base that the model uses. Each member then discussed various aspects of the undiscovered resource base—field sizes and distribution, regional definition of the United States, reservoir depth onshore, water depth offshore, etc.

Although each participant brought an estimate of the resource base to the discussion based on a variety of assumptions and methods, open discussion of the details of each was not possible because several of these estimates are proprietary. Consequently, the group discussed ranges of assessments and through this discussion reached a consensus as to the approximate size of the undiscovered resource in each region of the model. Following the groups' consensus of the resource base in each region, the resource base in the model was reviewed and revisions recommended. Feedback and comments from the entire Conventional Gas Work Group were obtained and incorporated, resulting in a consensus assessment of the undiscovered resource.

For the 1999 Study, the New Field resource assessments made in the 1992 Study were reviewed by the regional resource assessment subgroups in light of more recent discovery trends. The regional resource assessment subgroups made changes where the industry expectations differed from the prior assessment. Table S-37 compares the regional assessments of the two studies on an advanced technology basis. The most significant New Field changes were an increase in the New Field oil and gas potential in the deepwater Central & Western Gulf of Mexico and an increase in the Eastern Gulf of Mexico. Other notable changes include reductions in the gas potential in the deep Mid-Continent Region and deep Permian Basin. The details of the New Field resource base assumptions are contained in Chapter One of this Supply Task Group Report.

Nonconventional Gas

The Enhanced Recovery Module covers the portion of the assessed resource base that falls outside the scope of the "conventional" oil and gas field discovery process dealt with elsewhere in the HSM. The Enhanced Recovery Module includes nonconventional gas classified as coalbed methane, shale gas,

TABLE S-37

ESTIMATES OF NEW FIELD POTENTIAL LOWER-48 STATES AND CANADA BY REGION (Billion Cubic Feet; Technically Recoverable)

Region*		1992 NPC Study† (as of 1/1/91)	1999 NPC Study (as of 1/1/98)
A	Appalachia	27,302	27,772
B	Eastern Gulf Onshore	11,999	8,674
C	North Central	9,328	9,796
D	Arkla – East Texas	22,060	22,196
E	South Louisiana	16,715	11,838
G	Texas Gulf Onshore	53,502	52,550
WL	Williston Basin	3,006	3,088
FR	Rocky Mtn. Foreland	64,023	99,180
SJB	San Juan Basin	3,988	2,209
OV	Overthrust Belt	13,430	6,731
JN	Mid-Continent	59,215	39,675
JS	Permian Basin	30,318	31,353
L	West Coast Onshore	19,283	20,205
BO	Eastern Gulf of Mexico	15,376	40,655
EGO	Central & Western Gulf of Mexico	110,613	205,328
LO	West Coast Offshore	14,312	20,790
AO	Atlantic Offshore	18,714	30,580
Total Lower-48 States		**493,184**	**632,620**
ASM	Alberta, Saskatchewan, Manitoba	78,559	62,548
BC	British Columbia	30,727	32,465
NWC	Northwest Canada	74,202	80,972
EC	Eastern Canada	89,735	96,497
ART	Arctic Canada	106,381	111,051
Total Canada		**379,604**	**383,533**

*See Figure S-1 for map of regions.

†New Field values from the 1992 Study reflect re-allocation of certain resources among categories consistent with the 1999 Study.

and tight gas. The nonconventional gas is characterized by "cells," which represent resources in a specific geographic area. A cell can represent any size of area, ranging from the entire region/depth interval to a single formation in a few townships of a basin. Assumptions for each cell include areal extent of resource, well spacing, gas in place, recovery per well, and cost per well. Up to three different technology cases can be specified for each cell, along with assumptions about how the market share among the technologies will change over time. Over 200 cells were used to characterize the nonconventional gas resources for the 1999 Study.

NPC Assessment of Nonconventional Gas

For the 1992 Study, a Nonconventional Gas Subgroup was charged with establishing the recoverable resource base and reviewing the modeling of nonconventional gas in the HSM. These tasks were accomplished through subgroup work teams using information supplied by individual companies, and through consultant studies. Three overlapping work teams developed assumptions for tight gas, shale, and coalbed methane resources respectively.

TIGHT GAS

The NPC adopted the Federal Energy Regulatory Commission's legal definition of a tight formation—average in situ permeability of 0.1 millidarcy or less. The total undiscovered tight gas resource base consists of reserve growth potential in existing fields, and New Fields/reservoirs. The New Field resource consists of resources in existing (producing) plays and resources in new or undeveloped plays. Because gas quantities in existing plays (or play areas) are better understood and are evaluated separately in the model (they are included in the historical "find rate" equations), the NPC separated estimates for tight gas into existing and new plays. The "New Fields in new plays" category was modeled in the Enhanced Recovery Module.

In the 1992 Study, 47 tight gas plays were characterized by a mean recovery per well, total numbers of potential wells, capital and operating costs, and dry hole rates. The NPC based its estimates of Enhanced Recovery Module resource base, well recoveries, and costs on a confidential survey of operators in known tight gas formations. Respondents included five integrated companies, five independents, and two consultants. The survey included at least one operator from nine of the most significant tight gas producing basins and formations (Appalachian, East Texas/North Louisiana, Texas Gulf Coast, West Texas, San Juan, Denver, Piceance, Uinta, and Green River). Survey data were evaluated and transformed into consistent distributions of well recoveries and costs for use in HSM runs. Survey respondents provided detailed estimates of formations currently under development and their best judgment on remaining resources in their respective areas of expertise.

In areas not covered by the survey, and as a means to validate survey results, historical production data, and study results from the 1980 NPC study on Unconventional Gas Sources were used to estimate resource base and per well recoveries. Dwight's Energy well production data were used for producing wells in known tight formations to derive a distribution of expected ultimate well recoveries. These were used to calibrate survey results, or adapted as a basis for estimating ultimate recoveries of tight gas wells where no survey data were available. Since some of these formations contained non-tight wells, well distributions were adjusted to exclude these non-tight wells.

For the 1999 Study, EEA supplied each regional resource assessment team with the key assumptions used in the 1992 Study along with recent data of nonconventional gas drilling and production data for lower-48 plays outside of Appalachia. Each subgroup reviewed those data and the model projections to determine if adjustments were warranted. Table S-38 presents a comparison of the 1992 and 1999 assessments. One change made was a reduction in the most productive portion of the tight gas resources in the Alberta Basin. This change was caused by the belief that those resources were already captured in the conventional gas reservoirs represented elsewhere in the model.

SHALES

The principal known deposits of gas-producing shales are concentrated in the

TABLE S-38

COMPARISON OF TIGHT GAS RESOURCE ASSESSMENTS
(Trillion Cubic Feet; Technically Recoverable)

Region*		1992 NPC Study (as of 1/1/91)	1999 NPC Study (as of 1/1/98)
A	Appalachia	17.9	18.3
D	Arkla – East Texas	28.3	29.8
G	Texas Gulf Onshore	9.1	9.1
FR	Rocky Mtn. Foreland	137.2	137.0
SJB	San Juan Basin†	5.6	0.0
JN	Mid-Continent	16.9	16.9
JS	Permian Basin	19.5	19.5
	Lower-48 States	234.5	230.6
	Western Canada	89.0	86.8

*See Figure S-1 for map of regions.

†In the 1999 Study, San Juan tight gas is included with Old Field Reserve Appreciation and New Fields.

Appalachian, Michigan, and Illinois Basins in the eastern United States and in several Western basins. The Appalachian, Michigan, and Illinois Basin deposits have been characterized by delineating the black and gray shale horizons. The black shales have a higher gas content than the gray shales and are generally believed to be the predominant source beds of the natural gas found in the shales. Although the average total thickness of the shale deposits in the Appalachian Basin is many times greater than that found in the other two basins, a large part of the deposit consists of the poorer quality gray shales.

In the 1992 Study, EEA provided to the NPC a set of Devonian and Antrim shale resource estimates based on a 1980 NPC study of nonconventional gas, Potential Gas Committee estimates published in 1984, and work by GRI consultants. The NPC reviewed the estimates and made revisions based upon the field experience of some of its members. Estimates were not included for the Illinois and Western Basins because they were expected to remain undeveloped during the time frame of that study.

The original EEA data for Devonian shale in the Appalachian Basin encompasses 30 subdivisions, or "cells." Columbia Natural Resources (CNR) supplied Devonian shale production data from wells in counties of West Virginia, Ohio, Kentucky, and Virginia for use by the NPC in verifying the EEA's proposed assumptions. The EEA cell outlines were overlaid on state maps to determine the counties or portions of counties included in each cell. The National Petroleum Council made several comparisons of the EEA and CNR data. In general, the averages of the estimated recoveries of old and new wells drilled in a given EEA cell compared reasonably well with EEA's estimates. In some cells, there were sufficient differences to justify changing the estimates to reflect the CNR results.

During the 1992 Study, new information was supplied to the NPC by one of its members, indicating what area that would be productive for Antrim shale gas. These data were

TABLE S-39

COMPARISON OF DEVONIAN SHALE RESOURCE ASSESSMENTS (Trillion Cubic Feet; Technically Recoverable)

Basin (Region*)	1992 NPC Study (as of 1/1/91)	1999 NPC Study (as of 1/1/98)
Appalachian (A)	42.5	23.4
Michigan Antrim (C)	14.7	16.9
Illinois New Albany (C)	0.0	2.9
Cincinnati Arch (C)	0.0	2.2
Fort Worth Barnett Shale (D)	0.0	7.2
Lower-48 States	57.2	52.6

*See Figure S-1 for map of regions.

used to set drillable area, number of potential wells, and recovery per shale well in the Michigan Basin.

For the 1999 Study, the regional resource assessment groups reviewed the assumptions used in the 1992 Study and made several adjustments reflecting the current state of knowledge. Potential resources were reduced in the Appalachian Basin to reflect poor results from drilling in the last several years in certain areas. These areas were expected to be of relatively poor quality, but actual results were even worse than expected. In the Antrim shale in Michigan, certain cells were greatly reduced, while well recoveries were increased in the area of current activity. Table S-39 presents the results of the shale gas assessment.

The 1999 Study added shale resource characterizations for the Illinois Basin, the Cincinnati Arch, and the Fort Worth Basin. Data for the first two areas came primarily from resource assessments of the United States Geological Survey (USGS), while those in the Fort Worth Basin were based on input from an NPC member active in the area.

COALBED METHANE

For the 1992 Study, the NPC reviewed 20 coal basins of the lower-48 states, utilizing both proprietary and public data to determine the potential of these basins to produce methane in commercial quantities from the coals contained therein. These reviews utilized well logs and production data where available and built on the previous estimates of the Potential Gas Committee, the Department of Energy, and the Gas Research Institute. The coals in these basins range in age from Paleozoic to Tertiary and in depth from the surface to greater than 10,000 feet. Coal rank varies from subbituminous to anthracite.

Several basins projected to contain substantial reserves in previous studies were downgraded to lesser potential based on more recent information; in some cases, these basins were excluded from the HSM input. Other basins were upgraded to higher levels of resources based on production data from the last few years, or new information on exploration successes or increased gas contents of the coals. The 1992 Study noted that there was considerable uncertainty about the productivity of the coals in many of the basins reviewed, because they had not been tested extensively.

Model inputs developed for the 1992 Study included gas in place; recovery per well; the number of wells per section; geological and combined success rate estimates; future investment patterns; operating costs per well; and production figures for water, carbon dioxide, and natural gas liquids. These parameters were obtained from published production and geological reports as well as from proprietary information provided by some operators in specific basins. In basins where information was scarce, not current, or unavailable, best-guess estimates were made, or several basins were lumped together and an estimate was made of total recoverable resources.

The basins reviewed in detail in the 1992 Study were the San Juan, the Black Warrior, the Piceance, the Raton, the Uinta, the Greater Green River, the Powder River, the Wind River, and the Northern Appalachian Basins. Also reviewed were the Cherokee and Forrest City Basins and the Central Appalachian Basin, but these were not included in the HSM. Other basins were discussed that may have potential but for which there were insufficient data to include in the model.

For the 1999 Study, the regional resource assessment groups reviewed the 1992 Study assumptions. In particular, the assumptions for recoveries per well were compared against actual results compiled by EEA from PI/Dwights production data. The most significant change coming from this review was a downgrading of the potential in much the Warrior Basin and the fringe areas of the Fruitland coal of the San Juan Basin. Also, based on the judgment of the study's Rocky Mountain Regional Resource Assessment Group, the potential for the Menefee coal in the San Juan Basin was reduced substantially.

The characterization of coalbed methane in the Rockies was changed by eliminating "general cells" representing several basins and substituting cells representing coals in specific basins. The data for these new characterizations came primarily from USGS assessments with the exception of the Powder River Basin, for which information from a company active in that area was used. New cells were also created for Midwest and Mid-Continent coals, again relying primarily on USGS assessments. Finally, the characterization of the Appalachian coals was modified to better reflect the results of intensive drilling in the last several years in Virginia. Table S-40 presents the current coalbed methane assessment and compares it with that of the 1992 Study.

TABLE S-40

COMPARISON OF COALBED GAS RESOURCE ASSESSMENTS (Trillion Cubic Feet; Technically Recoverable)

Region*		1992 NPC Study (as of 1/1/91)	1999 NPC Study (as of 1/1/98)
A	Appalachia	15.0	19.4
B	Eastern Gulf Onshore	10.0	5.2
C	North Central	0.0	2.5
FR	Rocky Mtn. Foreland	39.0	29.4
SJB	San Juan Basin	33.0	10.1
JN	Mid-Continent	0.0	7.4
	Lower-48 States	97.0	74.0
	Western Canada	128.0	74.0

*See Figure S-1 for map of regions.

Environmental Costs

The impact of environmental regulation on the cost of natural gas exploration and production is an important consideration in assessing the potential of North American natural gas supply to satisfy future demand expectations. More stringent environmental requirements will increase the cost of E&P operations, reducing the volume of natural gas supply available at a given price. The importance of environmental considerations and their impact on North American gas supplies warranted the establishment of a work group to focus on this issue.

The environmental work group included representatives of API, GRI, and the U.S. Department of Energy's Office of Fossil Energy. The group analyzed potential future environmental compliance requirements for natural gas exploration and production, and considered technological advances that could reduce the costs of compliance. This section describes the environmental regulatory and technology scenarios analyzed, the sources of data and methodology used to estimate associated compliance costs, the incorporation of the costs into the HSM, and the results of the model runs.

Environmental Regulatory and Compliance Technology Sensitivity Development

To estimate the impacts of potential future regulatory requirements, the Supply Task Group defined two regulatory regimes that encompass a plausible range of future environmental regulation. Technology regimes were also developed to represent a plausible range of future environmental compliance technology research and development. The results of the regulatory and technology scenario analyses formed a matrix from which three environmental regulation cases and one environmental technology research and development (R&D) case were selected for the HSM. (The use of the term "case" has several meanings in this document. Case refers both to the regulatory and technology regimes, and to the specific model sensitivities.)

Environmental Regulatory Cases

The two regulatory cases were analyzed—the Risk-Based Regulation case and the Stringent Regulation case. These cases are discussed below.

RISK-BASED REGULATION CASE

Environmental compliance costs for this case are developed assuming a level of environmental regulation that effectively protects human health and the environment, balances the costs and benefits of environmental regulations, and recognizes the value of domestic natural gas production. In short, this case assumes a balanced, risk-based approach to future environmental regulation and initiatives. Environmental compliance requirements are allowed to increase in the future and are based on risk assessment and scientific data about the impacts of the regulated activities, the effectiveness and benefits of the compliance requirements, and the total cost of compliance. The environmental compliance costs developed for the Risk-Based Regulation case are *above current costs.*

STRINGENT REGULATION CASE

The Stringent Regulation case assumes a level of future environmental regulation that represents a willingness to forego some quantity of gas supply to gain perceived environmental benefits. Regulatory decisions are made without full consideration to their impact on the supply and use of natural gas. Although the environmental compliance costs developed for the Stringent case are substantially greater than the costs for the Risk-Based case, the Stringent case is not a "highest cost" or "worst case" scenario. Rather, the Stringent case assumes that natural gas E&P activities are subject to increasing environmental regulation that heavily weights environmental risk reduction over the cost and economic impact of reducing such risk.

Environmental Technology Cases

Two environmental technology cases were defined. The Current Technology case defines a scenario in which no substantial environmental technology R&D occurs and no compliance cost savings are realized. The Environmental Technology R&D case describes a level of sustained environmental technology R&D that yields potential future environmental compliance cost savings.

CURRENT TECHNOLOGY CASE

The Current Technology case assumes a level of environmental compliance technology available to the majority of producers today, and includes the phasing in of technology that is expected to become commercial within the next few years. This case assumes no future government funded research programs, and diminished industry investment in environmental technology research and development. Industry environmental R&D initiatives are assumed to focus only on technology needed for near-term environmental compliance.

Environmental compliance cost savings were not developed for the Current Technology case. These cost savings are included in current gas and oil field cost data and, as such, are already captured by the HSM.

ENVIRONMENTAL TECHNOLOGY R&D CASE

The Environmental Technology R&D case assumes that an increased level of compliance technology becomes available through a dedicated program of government and industry research and development. This case assumes that current R&D budgets for government and industry stabilize, that future environmental R&D budgets increase moderately, and that government research is oriented towards effective technology transfer to industry. Potential impacts of this case should be compared to the cost impacts of the Risk-Based Regulation case, with the result being the potential incremental benefit of technology R&D.

Estimation of Incremental Environmental Compliance Costs

ENVIRONMENTAL ISSUES AND AFFECTED INDUSTRY ACTIVITIES

The starting point for estimating future environmental compliance costs was a comprehensive review and update of projected environmental initiatives and emerging technology conducted in 1998 by the DOE Office of Fossil Energy's Oil and Gas Environmental Program. Representatives of API, GRI, and the Office of Fossil Energy updated DOE's 1998 review and, for each area of environmental concern, identified E&P activities likely to be significantly affected by future environmental regulatory initiatives or technology development. Table S-41 lists the E&P activities selected for the NPC's consideration of future environmental compliance costs.

METHODOLOGY USED TO ESTIMATE FUTURE COMPLIANCE COSTS

Since forecasting future environmental compliance requirements and costs is a highly uncertain exercise, an "expected value" approach was used to estimate environmental compliance costs for each of the 27 E&P activities defined in Table S-41. ICF Consulting initially developed the incremental compliance cost calculations for the 27 issues as part of the DOE Office of Fossil Energy's 1998 analysis of Oil and Gas Environmental Program impacts.[1] The costing data used to estimate future compliance costs came from a variety of sources including published reports, surveys, and analyses of environmental initiatives and emerging technology by API, GRI, and DOE. Other sources included reports prepared by the Minerals Management Service and the Environmental Protection Agency (EPA), and other documentation pertaining to regulatory initiatives. A third category of sources included issue-specific industry studies and surveys conducted by various organizations to analyze special issues (for example, the 1998 State Survey of Coalbed Methane Activity by the Ground Water Protection Council). After review by the environmental work group, the 1998 compliance cost calculations were revised and updated for this analysis. The methodology used is as follows:

- *Two to four alternative compliance requirements or technology development scenarios were developed for each industry activity area.* The scenarios either define a reasonable range of stringency for future regulatory requirements, or define a range of applications and market penetration for future technology. For example, the four alternative compliance scenarios for Onshore Drilling Waste Management consider increasingly stringent restrictions on the discharge and disposal of drilling waste.

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[1] Internal DOE document, "DOE Oil and Gas Environmental Program Metrics: 1998 Analysis and Results."

TABLE S-41

INDUSTRY EXPLORATION AND PRODUCTION ACTIVITIES BY ENVIRONMENTAL ISSUE

Environmental Issue	Industry E&P Activities Affected by Regulatory Compliance Issues	Industry E&P Activities Affected by Environmental Technology R&D Issues
Drilling and Drilling Waste Management	1. Onshore Drilling Waste Management 2. Offshore Drilling Waste Management 3. Offshore Drilling Synthetic Drilling Fluids 4. Drilling in Wetlands	17. Offshore Drilling with Synthetic Drilling Fluid 18. Wetlands Mitigation
Produced Water Management	5. Offshore Produced Water Disposal	19. Onshore Produced Water – Volume Reduction 20. Onshore Produced Water – Water Treatment 21. Offshore Produced Water – Volume Reduction 22. Offshore Produced Water – Water Treatment
Production Waste Management	6. Associated Waste Management 7. NORM Waste Disposal 8. NORM Contaminated Equipment	23. NORM Waste Management & Minimization 24. Salt Cavern Disposal of Non-Hazardous E&P Waste
Remediation	9. NORM Contaminated Soil	25. Remediation of Hydrocarbon Contamination 26. Remediation of Saltwater Contamination
Air Emissions	10. Onshore Air Emission Control 11. Offshore Air Emission Control 12. Control of Stationary Sources of PM 2.5 and Regional Haze (NOx, SOx, & VOC)	27. Greenhouse Gas Emission Reduction
Underground Injection Control	13. Hydraulic Fracturing	
Discharge and Releases	14. NPDES Storm Water Permitting 15. Toxic Release Inventory	
Regulatory Streamlining	16. Regulatory Streamlining	

- *For each individual scenario, a unit cost of compliance or unit cost savings is calculated.* Compliance costs are expressed in $/new well. The unit costs of compliance may be different for the Risk-Based and Stringent Regulation cases. Costs vary by region, depth, and resource type.

- *A probability of occurrence and year of implementation are estimated for each scenario appropriate to the philosophy underlying each case.* For individual scenarios, different probabilities are assigned in the Risk-Based and Stringent Regulation cases. In general, higher probabilities are assigned to more stringent scenarios in the Stringent case. Within each case, Risk-Based, Stringent, or Technology R&D, the sum of probabilities for individual scenarios must equal 1.00.

- *For each scenario, the unit cost of compliance or unit cost savings is multiplied by its probability.* The probability-weighted costs for individual scenarios are summed to obtain a final "expected value" compliance cost for each industry E&P activity.

- *Future incremental compliance costs for all industry activities are summed by applicable year of implementation to provide the total "per well" incremental compliance cost for a given year.* The assigned year of implementation determines the year in which the incremental cost is applied. In the Environmental Technology R&D case, new technologies are assigned a year of initial implementation and are assumed to follow a market penetration curve, achieving a target penetration (often less than 100 percent of wells) in eight years. The Risk-Based and Stringent regulatory compliance cases require incremental compliance costs (additions to present costs) whereas the Environmental Technology R&D case produces cost savings to industry.

- *The total incremental compliance costs for each case are input to the HSM as capital costs or operating costs applied to oil or gas wells.* The costs are specified in the model by region, depth interval, and resource type. This analysis focuses primarily on federal environmental requirements and assumes that most of the regulatory initiatives considered are applied nationwide. Site-specific costs are incorporated into the analysis for specific situations and issues (e.g., wetlands, offshore areas, remediation, hydraulic fracturing, etc.).

A "Stringent Fracture Case" was developed to portray the impact of just one significant regulatory change. This sensitivity case imposed additional high costs on all hydraulically fractured gas wells in the United States. This issue falls under activity #13 (hydraulic fracturing) in Table S-41. Such a scenario is a possible outcome of a recent 11th Circuit Court of Appeals decision in the case of *LEAF v. EPA*. In that federal appeals court decision, hydraulic fracturing of coalbed methane wells in Alabama was determined to be subject to regulation as underground injection under the Safe Drinking Water Act. The EPA argued that this was never intended under that law and no environmental damage from such fracturing has ever been documented. The immediate result has been to add regulatory testing and permitting requirements, costing an estimated $17,000 per well, for hydraulic fracturing of coalbed methane wells in Alabama. The opinion of this court has the potential to be applied nationwide to any type of hydraulically fractured well. Additional testing and diagnostic requirements that may result from this nationwide application of the ruling have been estimated by API to increase costs up to an additional $67,000 cost on every hydraulically fractured gas well in the United States. In addition to increased costs, potential restrictions on the types of fracture fluids that could be used would decrease well productivity and, thus, further decrease future production. However, the sensitivity case does not take into account this probable loss of fracture effectiveness that would result from these restrictions.

LONGER-TERM REGULATORY INITIATIVES AND TECHNOLOGY DEVELOPMENT

The expected value approach described above is effective for estimating costs for regulatory and technology scenarios that can be defined and implemented to the year 2005. Although future regulatory requirements beyond 2005 are highly uncertain, this analysis assumes that future undefined requirements will cause compliance costs beyond 2005 to increase. Similarly, the Environmental Technology R&D case assumes that a sustained level of research and development will maintain a level of technology development that yields long-term compliance cost savings.

After year 2005, the incremental environmental compliance costs for the Risk-Based and Stringent Regulation cases are increased at an annual rate based upon the average rate of compliance cost increase during years 2000 to 2005, the period for which specific environmental compliance requirements are identified. Similarly, for the Environmental Technology R&D case, incremental compliance cost savings are increased at an annual rate which continues the trend of cost savings from technology development during years 2000 to 2005. For all cases, the longer-term cost (or savings) growth rates are different for capital costs and annual operating costs. The longer-term compliance costs and cost savings increase at 5% (real dollars) annually for both gas and oil capital costs. For operating costs, the annual increase in compliance cost ranges from 8% for onshore gas wells, 10% for offshore gas and oil wells, and 14% for onshore oil wells.

Average costs per well are shown in Table S-42 under Incremental Environmental Expenditures ($/well drilled). This table illustrates the cost differences between the scenarios and shows the cost escalation. The average expenditure per well ranges from a low of $150 per well in 2000 for the Environmental Technology R&D case to a high of $69,000 per well in 2015 for the Stringent Regulation case.

Modeling Approach

Four environmental regulatory and technology scenarios were modeled for the 1999 Study using the HSM. The Risk-Based Regulation cost scenario was included in the Reference Case, while the three other cases were run as sensitivities from the Reference (Risk-Based) case. The four scenarios are listed below in order of increasing impact:

1. Environmental Technology R&D Case
2. Risk-Based Regulation Case
3. Risk-Based Regulation with Stringent Case Hydraulic Fracture Costs (Stringent case environmental costs for hydraulic fracturing added to the Risk-Based scenario)
4. Stringent Regulation Case.

The HSM was run to model the impact of environmental regulation and technology on new wells. The HSM module that models the impact of environmental costs on existing wells was not run for the 1999 Study. This module was used in the 1992 Study. A review of the 1992 results showed that the abandonment of existing wells reduced average annual production by about 0.25% in the Low Impact case, and by about 1.7% in the High Impact case. The 1992 Low Impact case is more comparable to the 1999 Study; the 1992 High Impact case is much more severe than the current Stringent Regulation case. In light of the expected small impact of environmental compliance costs on existing wells, the existing well analysis was not updated for the 1999 Study.

Modeling Results

The Stringent Regulation case has the greatest impact on production, price, and drilling. By 2015, the additional costs imposed under the Stringent Regulation case result in a decrease in lower-48 gas production of 723 BCF (3%), and an increase in the Henry Hub gas price of $0.20 per MMBtu (5%) compared with the Reference Case. Total well completions for the Stringent Regulation case are 4,743 (10%) less than the Reference Case in 2015. Conversely, the compliance cost savings under the Environmental Technology R&D case result in a modest annual production increase of 75 BCF and a $0.01 per MMBtu decrease in gas price by 2015.

These impacts are in addition to the impacts of the Risk-Based environmental assumptions contained in the Reference Case. The Risk-Based compliance costs result in an annual production decrease of up to 170 BCF, a decrease in annual gas well completions of up to 1,400 wells, and a gas price increase of $0.05 per MMBtu compared to a case without these costs.

Extra environmental expenditures under the Stringent Regulation case reach $3 billion

TABLE S-42

RESULTS OF ENVIRONMENTAL REGULATORY AND TECHNOLOGY CASES

Lower-48 Annual Gas Well Completions	2000	2005	2010	2015
Environmental Technology R&D Case	11,594	11,311	16,588	23,851
Reference Case (Risk-Based Regulation)	*11,593*	*11,400*	*16,505*	*23,830*
Risk-Based + Stringent Fracture Costs	11,561	11,124	15,849	21,654
Stringent Regulation Case	11,554	11,173	15,397	20,746

Lower-48 Total Annual Well Completions	2000	2005	2010	2015
Environmental Technology R&D Case	23,117	25,182	37,495	49,084
Reference Case (Risk-Based Regulation)	*23,116*	*25,180*	*37,252*	*48,438*
Risk-Based + Stringent Fracture Costs	23,080	24,838	36,798	46,318
Stringent Regulation Case	23,065	24,633	35,099	43,695

Lower-48 Annual Gas Production (Billion Cubic Feet)	2000	2005	2010	2015
Environmental Technology R&D Case	19,465	22,097	24,678	26,146
Reference Case (Risk-Based Regulation)	*19,465*	*22,039*	*24,640*	*26,071*
Risk-Based + Stringent Fracture Costs	19,465	22,008	24,538	25,730
Stringent Regulation Case	19,465	21,938	24,328	25,348

Henry Hub Natural Gas Price (1998 Dollars per Million Btu)	2000	2005	2010	2015
Environmental Technology R&D Case	$3.21	$2.83	$3.18	$3.75
Reference Case (Risk-Based Regulation)	*$3.21*	*$2.85*	*$3.19*	*$3.76*
Risk-Based + Stringent Fracture Costs	$3.21	$2.87	$3.24	$3.86
Stringent Regulation Case	$3.21	$2.90	$3.31	$3.96

TABLE S-42 (CONTINUED)

Total Incremental Impact of Increased Environmental Expenditures* (Millions of 1998 Dollars)	2000	2005	2010	2015
Environmental Technology R&D Case	$4	$205	$462	$757
Reference Case (Risk-Based Regulation)	*$12*	*$482*	*$810*	*$1,202*
Risk-Based + Stringent Fracture Costs	$25	$853	$1,205	$1,678
Stringent Regulation Case	$36	$1,314	$2,042	$2,997

Incremental Environmental Expenditures* (Dollars per Well Drilled)	2000	2005	2010	2015
Environmental Technology R&D Case	$154	$8,136	$12,326	$15,422
Reference Case (Risk-Based Regulation)	*$505*	*$19,139*	*$21,731*	*$24,816*
Risk-Based + Stringent Fracture Costs	$1,076	$34,341	$32,743	$36,226
Stringent Regulation Case	$1,552	$53,344	$58,166	$68,590

Incremental Environmental Expenditures* (Dollars per MCF Produced)	2000	2005	2010	2015
Environmental Technology R&D Case	$0.00	$0.01	$0.02	$0.03
Reference Case (Risk-Based Regulation)	*$0.00*	*$0.02*	*$0.03*	*$0.05*
Risk-Based + Stringent Fracture Costs	$0.00	$0.04	$0.05	$0.07
Stringent Regulation Case	$0.00	$0.06	$0.08	$0.12

Change in Lower-48 Annual Production (Billion Cubic Feet)	2000	2005	2010	2015
Environmental Technology R&D Case	0	58	38	75
Reference Case (Risk-Based Regulation)	*0*	*0*	*0*	*0*
Risk-Based + Stringent Fracture Costs	0	-31	-102	-341
Stringent Regulation Case	0	-101	-312	-723

*Represents expenditures for environmental mitigations above those in existence in 1998.

(constant 1998 dollars) in 2015, while these expenditures reach $757 million in the Environmental Technology R&D case. Impacts from the Risk-Based Regulation with Stringent Fracture Costs case fall between the Stringent Regulation and Environmental Technology case impacts. The results of the environmental impact cases are summarized in Table S-42. The cases are sorted in order of increasing impact.

The model results show that increased environmental compliance costs for new wells would have a significant impact on drilling, production, and gas price. The largest impacts are under the Stringent Regulation scenario. Comparison of the Stringent Regulation results to the Reference Case shows that the largest impact is on well completions. Gas well completions decrease by 13% (3,084 wells), and total completions (oil, gas, dry) decrease by 10% (4,743 wells) in 2015. The impact on production is smaller as a percentage difference from the Reference case, but is significant at 2 BCF per day lost by 2015. Gas prices are $0.20 per MMBtu higher under the Stringent Regulation case than the Reference Case in 2015. Incremental environmental expenditures for the Stringent Regulation case average $0.12 per MCF produced in 2015.

Results from the Environmental Technology R&D case show the smallest environmental compliance impact of the four cases. Lower environmental costs under this case result in small *increases* in drilling and production compared to the Reference Case. By 2015, total well completions increase by 1% (650 wells), and gas well completions increase by less than 1% (21 wells) over the Reference Case. Gas production in 2015 is 75 BCF greater than the Reference Case, an increase of less than 1%. Gas prices are comparable to the Reference Case.

The Risk-Based Regulation with Stringent Fracture Costs sensitivity produced impacts between the Reference Case (Risk-Based Regulation) and the Stringent Regulation case. The addition of the increased environmental costs associated with hydraulic fracturing resulted in a significant decrease in gas well completions (2,176 wells in 2015) compared to the Reference Case. This decrease is 70% of the gas wells impact of the Stringent Regulation case.

The environmental compliance impacts presented in this document are for new wells. The impact of environmental regulation on existing wells was not modeled. The 1992 Study did use the HSM to model environmental compliance impacts on existing wells. The 1992 Study, while not comparable to the environmental scenarios considered for this study, showed an average annual impact production of less than 1% over a 20-year forecast period.

Conclusions

Future environmental regulations and legislation could impose unnecessarily high costs on natural gas exploration and production, significantly limiting the efforts of the industry to supply increasing natural gas demand at a competitive prices. Such costs would result in reduced production and higher natural gas prices.

The key issue is whether increasingly stringent environmental requirements in fact result in better environmental quality. Requirements should not be imposed only to achieve perceived environmental benefits, or to minimize environmental risk without considering the costs. To do otherwise would result in increased natural gas prices, impairment of the competitive position of natural gas and, ultimately, enhancement of the competitive position of less environmentally friendly fuels without any commensurate benefit. The modeling results give an indication of the magnitude of the cost and production impact of unnecessarily stringent regulation.

Environmental regulation should be based on environmental risk assessment and sound science. Such risk-based regulation is protective of the environment while balancing the costs and benefits of environmental compliance. This regulation must also be done within a national policy context that values natural gas use for its positive contributions toward improving air quality and mitigating global climate change. These benefits should weigh heavily in considering the environmental impacts of natural gas exploration and development activity.

Environmental technology R&D can also make a contribution to lowering the cost of environmental compliance while improving the environmental performance of E&P

activities. This can save the industry a considerable amount of money, thus freeing funds for further resource development.

Financial Methodology

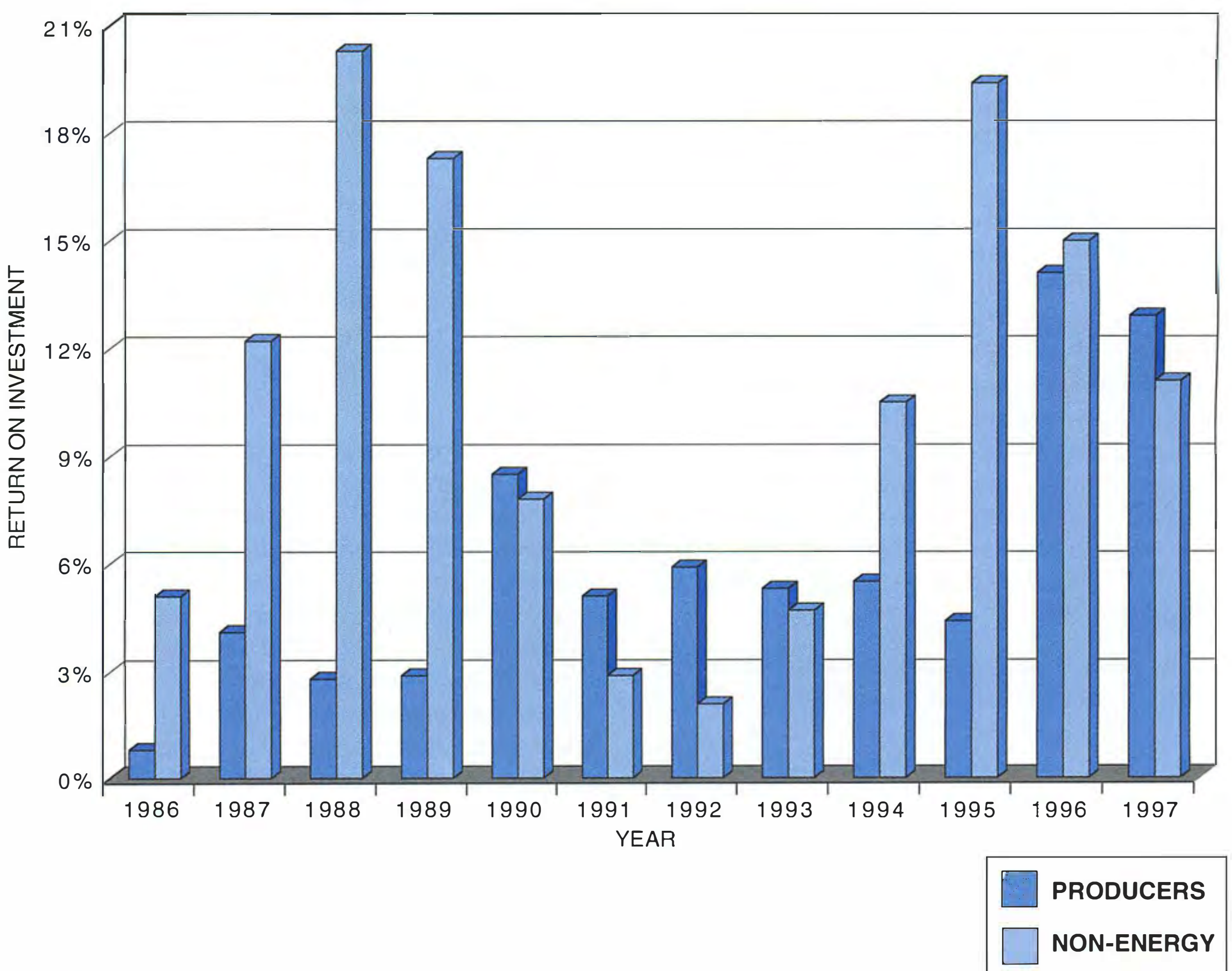
Overview of Past Industry Financial Performance

Figure S-60 shows E&P performance in terms of Return on Investment, as per the EIA over the past several years. In the time period plotted in this figure, the average Return on Investment is 5.4%. Figure S-60 illustrates that industry investment is also dependent on oil and gas price swings.

The oil price decline that was seen in late 1997 impacted the industry negatively. This price decline caused a reduction in industry cash flow. This in turn contracted capital budgets, creating severe financial stresses, especially in the service sector. As a result, the industry is now going through, to quote one analyst, a period of "capital starvation." This has impacted the smaller independent companies more than the larger companies. The "capital starvation" has impacted the capital markets in the following ways:

- **Equity Markets.** The lower than desired returns forced companies to postpone either Initial Public Offerings or the issuance of additional shares via secondary offerings.
- **Debt Markets.** This is the area that impacted the independents more, given that their capital structures are more

Figure S-60. Rates of Return, 1986–1997
Oil & Gas Producers vs. Non-Energy



SOURCE: *EIA Performance Profiles of Major Energy Producers*, January 1999.

leveraged. The pressure felt here was especially pronounced with Borrowing Base Bank Debt. This form of debt is subject to periodic review by commercial banks (at least once a year) and is a function of a company's discounted cash flow from proved reserves. With the price declines experienced in late 1997 and early 1998, borrowing base levels declined, forcing some companies to divert cash flow to debt repayment, instead of capital expenditures.

Although both oil and gas prices recovered in late 1999, the industry's psychological state of mind was still rather depressed. It was in this backdrop of somewhat depressed conditions that the Supply Task Group attempted to make financial estimates.

Study Projections

Financial Parameters Used in Model. The task of the Supply Task Group was to determine financial assumptions that most closely reflect the North American E&P environment. The Supply Task Group engaged various sources to determine the values of the model's various financial parameters. A summary is shown in Table S-43.

TABLE S-43

SUMMARY OF FINANCIAL PARAMETERS

Financial Parameter	Value
Interest Rate	7.0%
Capital Structure	60% Equity, 40% Debt
U.S. Income Tax Rate	30%
Dividend Payout Ratio	20%

Interest Rate. The assumption of 7% was determined using an industry "blended average." This was determined by calculating an effective interest rate from the financial statements of publicly traded E&P companies.

Capital Structure. Like the interest rate assumption, this was based on financial statement analysis. One general observation was that major companies are typically less leveraged than independents. The above debt–equity mix was arrived at in consideration of the following points:

- A "blended" major–independent capital structure weighted by present gas production
- A belief that capital structures will be slightly less leveraged.

Income Tax Rate. The value is based on the average income tax rate for the independent sector in 1996. The inclusion of the average tax for major oil and gas companies was problematic for the following reasons:

- A substantial amount of their operations comes from foreign operations
- A significant portion of taxable income comes from non-E&P activities.

Dividend Payout Ratio. The payout ratio was based on a weighted average from both majors and independents.

Technology

There is little doubt that technology is a critical driver for the performance and growth of the natural gas industry in the North America. This is compounded by the complexity of the current and future resource base, in which long-term success will depend on reservoirs that are deeper, more geologically challenging, and harder to reach, define, complete, and manage. Continued development of multi-disciplinary and cross-company teams utilizing high levels of connectivity and knowledge management/acquisition systems will be required. Effective management will require creating and managing symbiotic relationships within companies and with external groups, such as partners, suppliers/vendors, and additional links in industries outside the energy sector.

Significant Future Technologies

The following brief capsules are intended to highlight some of the technologies that are expected to have significant influence on the ability of industry to provide adequate gas supplies in the future, as envisioned by the NPC Technology Group.

4D Seismic. In the future, we will see a coupling between surface seismic and permanent downhole seismic sensors. As a field is developed, each well will include permanent downhole geophones. The sensor system will enable us to see great increases in seismic detail as a result of the simultaneous use of surface sources and sensors as well as permanent downhole seismic sensors.

3D Shear Wave Seismic. Compressional wave seismic in use today uses only part of the possible energy spectrum to image the reservoir. Shear wave seismic offers a new dimension in which to image the reservoir in detail sufficient to define compartmentalization and hence increase in-field development and extension potential.

Real-Time Reservoir Model. An enormous amount of all types of data will be produced in the future and the reservoir model must incorporate these data in real-time, all the time modifying the assumptions of the model. In order to keep up with the anticipated large increases in data, both the model algorithms and computing hardware will require constant updating to state of the art capability.

Deep Wireline Measurements. Deep measurements such as gravity and electromagnetics provide information that is similar to but complementary to seismic. Wireline-based deep measurements typically have higher resolution than seismic and can provide enhanced detail about gas location and movement. In the future, we will see deeper, higher resolution measurements with greater accuracy. These will also feed into the reservoir model mentioned above.

Integrated Well Planning. Planning programs and systems would link to reservoir and economic models in order to optimize well placement in an overall exploration and reservoir management plan. By utilizing an integrated, data-rich environment, a more holistic planning process can be used, resulting in maximized planning efficiency, better cost/profit controls, and the ability to simulate multiple scenarios in a time-effective manner. Interconnectivity between the wide range of disciplines involved would also have the potential of significantly decreasing cycle time. Overall, an integrated planning process would have significant benefit in decreasing uncertainties and increasing well/field and reservoir efficiency.

Drilling Systems. The drilling segment will be continually challenged to develop and implement technologies to "bring the wellbore" to specific horizons of interest and greatest economic value. This will become increasingly important in natural gas reservoirs, as industry looks at deeper, hostile environments, more complex and areally compact reservoirs, and to do so in an environmentally friendly manner. Bottomhole assemblies allowing far greater reliability in wellbore placement will be coupled with technologies such as retractable bits, high durability bearings, high horsepower/high pressure drilling motors, and enhanced well-control processes and equipment. Second and third generation synthetic muds will allow greater lubricity, cuttings transportability, and greater formation and environmental compatibility. Many of these technologies are considered cutting edge today. However, strong technical and developmental efforts will continue due to the necessity of decreased cost and increased efficiency of connecting the surface to the reservoir.

Expandable Tubulars. Expandable casing in the future holds promise to reduce the overall cost of development because casing strings will not be required to run back to surface and eliminate the need for casing/liner hangers. The expandable casing can be welded into place, reducing the need for casing hangers and liner tieback equipment. In ultra-deep water (10,000 feet of water depth and greater) many of these prospects are not drillable due to excessive mudweights and number of casing strings to reach total depth. Another future application of this technology is expandable screens. This has the potential to cut completion costs significantly, due to time savings, elimination of at least a portion of the downhole completion equipment, and reduction of the need for annular gravel packing.

Rigless Spoolable Completion Systems. Spoolable completion systems have tremendous potential as a cost saver. Large diameter composite tubulars would be expected to have greater durability, work at greater depths, and offer significant weight advantages for either on-platform or vessel usage. An additional advantage would be the capability of building the tubulars with smart conductors and pre-built accessories such as sliding side doors, nipples, sensors, flow controls, and side-pocket mandrels. The possibility of working through spoolable, lightweight removable risers to make the operation more efficient and less costly would also be significant. The same type of applications might be applicable to land operations, but limitations would exist in tubular length and diameter due to transportability issues.

Stimulation. It is anticipated that in the future there will be some changes in the basics components of hydraulic fracturing and reactive fluid (acid, etc.) treatments. Research will continue on stimulation fluids that are less damaging to the reservoir, are environmentally benign, and are less costly. The greatest potential lies in the area of simulations utilized during the planning phase and real-time job operations. Enhanced capability to utilize highly detailed and integrated geologic, mechanical, reservoir property, and economic factors in treatment design and implementation will bring great value. Artificial intelligence, robust sensors, object technology driving data integration, and concurrent implementation by linked, virtual cross-functional centers of expertise are critical areas of focus. Success in this arena will be important factor in the 10+ year time frame based upon projections of greater dependence on complex tight gas sands and nonconventional resources (coalbed methane, shale, etc.).

Subsea Processing. Development of and improvements in subsea separation, metering, and pumping will decrease the need for surface facilities and associated risers. It can be envisioned that a major portion of the deepwater Gulf of Mexico out to about 10,000-feet water depth could be produced using only subsea equipment tied back to relatively shallow water and less expensive host platforms. A related technology is cold flow, i.e., the ability to transport produced fluids and gasses at low ambient temperatures. This approach would allow fewer and less-expensive flowlines and the ability to flow these products long distances at reasonable pressures.

Free-Standing Drilling Risers. Deepwater moorings and free-standing risers are brought together in what several suppliers have been calling "Installation In Advance." This name is derived from the fact that both the moorings and the riser can be installed prior to the arrival of the drilling rig. The installation is done by a special vessel referred to as the "installation vessel" (probably a converted second- or third-generation rig), which can be either a moored or dynamically positioned vessel. The installation vessel might also install surface casing to increase the efficiency of the drilling vessel even further.

Polyester TLMs. Using the new technology of taut leg moorings (TLMs), together with polyester mooring lines and anchors that can withstand uplift, will allow a drilling rig to keep a very tight watch circle (less than 2% of water depth). This would apply even under severe environmental conditions that would require disconnection of the drilling riser using a conventional catenary mooring system with steel components. It will also be safer to install the polyester TLMs since the loads that have to be handled are greatly reduced. Also, a polyester mooring is much safer if it is dropped (for example on a pipeline or wellhead) than a heavy steel line. Finally, the environment is spared the air pollution that results from continuously running a dynamically positioned rig to keep it on station.

Polyester TLMs also have potential to be used on production facilities in the future for many of the same reasons, i.e., to decrease the loads on the vessel (save on buoyancy costs), maintain tighter watch circles (simplify risers), increase safety in case of dropping a mooring line, and generally reducing costs.

Preset polyester moorings can be of great benefit in mooring a vessel to do intervention work for subsea satellite wells. One example is an operator that plans on requiring a moored rig if the intervention involves the pulling of tubing. Polyester TLMs have distinct advantage over steel moorings in such a situation due to the large amount of equipment on the seabed that could be damaged in the event a line was dropped. Again, this technology has the potential to save money and reduce risk to the environment.

Dual Density Drilling. A current example of the new era of drilling equipment design is the dual density/activity drillships currently entering the ultra-deepwater plays. These rigs are designed to make deep cuts in drilling time and associated costs and thus reduce total well costs. A number of highly innovative designs were utilized in terms of station keeping, deck loading, well testing capabilities, two complete drilling systems under a single derrick as well as unique high capacity drilling fluids and blow-out preventer/riser systems. Another feature of this new approach is the utilization of multi-discipline teams of vendors, contractors, and operators to make critical planning decisions. Experienced gained from this type of design and implementation is an example of how major cost segments of the well construction process can be mitigated by innovation, research, and critical path functionality to promote significant cost efficiencies. It is anticipated that this process will continue to drive further savings and efficiencies in the future, both in offshore and onshore operations.

Production Facilities. Production and gathering facilities are a significant cost factor in all offshore operations. Thus, highly focused technology efforts are and will continue to be applied to this segment.

Production Facilities Design. In the future, it is anticipated that enhanced computer-aided design and linked simulation based design of facilities will be directly tied to comprehensive subsurface earth models that allow for business analysis at each level of the field's life. Developments in these areas will lead to more complete, comprehensive, and consistent understanding of the overall system among the various groups within a company, which should lead to better estimates of capital and operating costs and of total system performance through the asset's life. In terms of cost, this will lead to facility designs that are highly performance-oriented and cost-effective over the entire field life. An example in very deep water might be replacement of multiple separate production facilities with a single large, floating regional processing and transshipping facility (no storage). The unit would be highly adaptable to configuration changes and tied to extended tiebacks to a large number of wells in the area. Subsea wellheads would be linked to remotely operated buoys with high-rate data links and moored with composite risers and unbilicals. As input volumes increased or decreased, required changes could be made in configuration. Advantage of this concept is that it is driven by marginal economics as could well be faced in the Gulf of Mexico in the long term, where fields are much smaller and further apart.

Impact of Information Technologies, Current Examples

Linkage of Geoscience and Engineering. Current technologies allow for cross-platform applications, which allow connectivity between the Unix-based seismic and geologic world and the PC base of the reservoir and design engineers. These technologies allow much greater data transfer and interdisciplinary team activities.

Visualization. Visualization allows explorationists and engineers the capability of viewing and manipulating massive amounts of 3D and other seismic and geologic data in a collaborative environment. Utilization of viewable data and highly sophisticated data management techniques is especially important in obtaining reliable information regarding the geology of subsalt deepwater plays in the Gulf of Mexico.

Integrated Visualization. A further enhancement of visualization technology is the integration of seismic/geologic information and well-planning capabilities. This allows specialists to plan and visualize 3D well paths directly in the 3D seismic volume. Using multiple scenarios and by monitoring real time well activities, tremendous cycle time reductions are possible. This concept is also applied to design of both integrated systems and mechanical devices/structures using computer-aided design and manufacturing and other similar tools, which allow multiple scenario investigation and ultimately less costly, enhanced fit for purpose facilities.

Connectivity. Utilizing the Internet, e-mail, desktop video, and other aids, companies can now stay in personal data-link communication with operations anywhere at any time. This allows for collaborative planning and operations regardless of location and can expedite problem solving and concurrent modeling of activities. Connectivity also promotes better availability and utilization of highly experienced personnel, in that they need not necessarily be at the well site or distant office to provide immediate/critical input and expertise.

Remote Control. Computer and sensor systems are currently being integrated into a host of unique and hostile environment applications. The advent of downhole production controls, "smart" tools, store and forward data systems, and remote direction of on-location activities are becoming more commonplace.

Technology Assumptions Used in the Hydrocarbon Supply Model

The technology drivers set in the HSM for the 1999 Study and two alternative cases are shown in Table S-44. The 1999 Study represents the study group's view of what can be expected for technological advances based on recent levels of R&D funding and the general effectiveness of those efforts. The Faster Technology Advancement case assumes either a higher level of funding or a greater-than-expected number of significant technological breakthroughs. The Slower Technology Advancement case envisages a decline in R&D funding with a resulting halving of each Base Case technological driver in the model.

An explanation of the parameters shown in Table S-44 is as follows.

New Field Exploration Efficiency. Improvements discussed above, such as 4D Seismic, Deep Wireline Measurements, Integrated Well Planning, and Improved Drilling Systems will greatly increased level of understanding of landing and keeping the well in the pay interval. The Supply Task Group envisions that the evolution of the above parameters may be somewhat geometric, resulting in the above percentages increasing over time.

Platform Cost Reduction. Items discussed above, such as Expandable Tubulars, Spoolable Completions, Free-Standing Drilling Risers, Polyester TLM, and Information Technology influenced the Supply Task Group's decision on this Model Driver. In arriving at the High Tech Driver of 4%, the

TABLE S-44

TECHNOLOGY DRIVERS SET IN HYDROCARBON SUPPLY MODEL

% Annual Improvement	Reference Case	Faster Technology Advancement Case	Slower Technology Advancement Case
New Field Exploration Efficiency			
2000	1.5%	2.5%	0.75%
2010	1.8%	2.8%	0.90%
2015	2.2%	3.2%	1.10%
Platform Cost Reduction	1.5%	4.0%	0.75%
D&C Cost Reduction			
Onshore & Shelf	2.5%	3.0%	1.25%
Deepwater	3.0%	3.5%	1.50%
Improvements in EUR per Well			
Conventional Gas	1.0%	1.5%	0.5%
Low Permeability Gas	2.1%	2.5%	1.05%
Nonconventional Gas	1.5-3.0%	1.5-3.0%	0.75-1.50%

Supply Task Group felt that cutting edge technologies like Free-Standing Drilling Risers and Polyester TLMs could have a major impact in an advanced stage of development.

Drilling and Completion (D&C) Cost Reduction. Almost all of the factors discussed above will impact D&C cost reductions. It was the Supply Task Group's opinion that the cost-reduction effect would be more pronounced in the deepwater Gulf of Mexico, resulting in the higher reduction value.

Improvements in Estimated Ultimate Recovery Per Well. The following items influenced the Supply Task Group's recommendation on the model drivers: Integrated Well Planning, Stimulation Techniques, Subsea Processing, and Information Technology. The Task Group envisions a higher improvement in Low Permeability and nonconventional gas as more future production comes from those classifications. Over the past several years, coalbed methane and fractured shales experienced a tremendous technology gain due to a concerted effort by producers, GRI, DOE, and the service industry, which was also spurred by tax credits.

TRANSMISSION & DISTRIBUTION TASK GROUP REPORT

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Summary of Key Findings of the Transmission & Distribution Task Group

The National Petroleum Council finds that significant expansion and enhancements to the delivery system are required to serve the growing demand for natural gas. The existing transmission and storage system is capable of meeting its existing firm requirements on an annual and peak-day basis. A significant investment in pipeline facilities will be necessary to meet the new demand requirements and shifts in supply locations to deepwater Gulf of Mexico, Rockies, western Canada, and the Canadian Atlantic. The forecasted average annual capital expenditures are slightly less than the average annual capital expenditures during the last three decades. Through 2015, approximately 38,000 miles of transmission pipeline and 255,000 miles of distribution mainlines are projected to be needed to meet the requirements of the future market. This rate of growth is not extraordinary and is in fact comparable to the expansion experienced in the last few years.

This level of expansion combined with enhancements to existing infrastructure should enable the transmission and distribution industry to meet the expected growth in U.S. natural gas demand well into the twenty-first century. Yet, there will be challenges along the way such as:

- Access issues that impede installation of new infrastructure
- The need for new services to meet the requirements of a changing market
- The restructured market changes the risks associated with investments for new infrastructure.

It is industry's challenge to attract the investment capital and human resources to build transmission and distribution pipelines, maintain the existing infrastructure, and serve new and existing customers. It is government's challenge to minimize impediments to a competitive marketplace for all sectors of the natural gas industry, including companies involved in the transmission and distribution of natural gas, while continuing to consider the effects of any residual market power they may possess. Such a relationship between government and the pipeline/distribution industry is essential to continue the efficient and reliable transportation of sufficient quantities of natural gas supplies to meet the nation's economic and environmental goals.

Key Findings of the Transmission & Distribution Task Group

1. Significant expansion and enhancements to the delivery system are required to serve the growing demand.
   - By 2015, annual requirements are projected to increase beyond 31 TCF.
   - Peak-day requirements will grow from approximately 111 BCF per day in 1997 to over 152 BCF per day in 2015.
   - Supply locations will shift to frontier areas such as deepwater Gulf of Mexico, Rockies, western Canada, and the Canadian Atlantic.
   - Through 2015, approximately 38,000 miles of transmission pipeline and 255,000 miles of distribution mainlines are projected to be needed to meet the requirements of the forecasted market.
   - Working gas storage may need to increase by 0.8 TCF.
   - Based on recent history, there is little concern that the projected increase in infrastructure will cause significant problems.

2. Access issues impede installation of new infrastructure.
   - Issues arise from urban sprawl encroaching on existing rights-of-way, heightened public resistance to providing easements, and increasingly restrictive government policies and regulations.
   - Unprecedented public protest has arisen to recently proposed pipeline projects from the Midwest to serve Northeast markets.
   - Recent proposed policy/regulatory changes demonstrate a movement toward additional requirements for the building and maintenance of pipelines.
   - Consequences of conflicting policy and regulations within and across government agencies will lead to higher costs, directly or via delays.
   - Natural gas has its own environmental benefits that should be taken into account when formulating policy so that an appropriate balance can be achieved.

3. New services are needed to serve a changing market.

- The current delivery system was built to meet the design peak-day requirements of LDCs whose loads were primarily residential, commercial, and industrial.
- Marketers, producers, and other end-users are contracting for capacity as the competitive market evolves and many of these customers use capacity differently than the LDCs.
- The tremendous growth in electricity generation demand for natural gas will require the delivery system to be re-optimized to meet larger off-peak swing loads as well as growing peak-day requirements.
- New high-efficiency gas-fired turbines for electricity generation require significantly higher inlet pressures and higher hourly flow rates than other end-use customers.
- Loads for peaking generators are volatile and of relatively short duration, thereby requiring greater flexibility and quicker responses by the natural gas delivery system.
- Meeting the requirements of electricity generators will entail changes in physical capabilities, operational procedures, communications, contracting (supply and transportation), and tariffs.

4. The restructured market changes the risks associated with investments for new infrastructure.

- The industry restructuring over the last two decades has led to changing roles and obligations—as well as new risks and different risk profiles—for all the industry participants.
- The Reference Case shows that transmission and distribution companies will need to make capital investments of approximately $123 billion through 2015 in the lower-48 states, which includes $35 billion for transmission facilities, $84 billion for distribution facilities, and $4 billion for storage facilities.
- The shippers' need to limit their long-term exposure does not align with the pipelines' traditional need for long-term contract commitments to justify investment risk.
- Faced with these changing conditions, it is not clear who will be willing to accept the risks for building the infrastructure needed to support the growth in natural gas demand.

General Methodology Overview

The responsibility given the Transmission & Distribution Task Group was to conduct an analysis of the natural gas delivery system (subject to the assumptions on supply and demand developed by the Supply and Demand Task Groups) including the identification of infrastructure and operational requirements, gas storage, right-of-way, and other issues, and to present the findings in this report.

The Transmission & Distribution Task Group was comprised of numerous participants representing the diverse viewpoints, perspectives, and interests of producers, interstate pipelines, local distribution companies (LDCs), marketers, and government. The group met several times over the 12-month study period to:

- Determine the approach and scope to, as well as the assumptions and sensitivities for, the transmission and distribution analyses
- Identify the critical issues/factors facing these industry segments based upon industry experience over the last seven years, current outlooks and trends, and the results of the model analysis.

The Transmission & Distribution Task Group's approach was to narrow the scope of the analyses and focus on examining the critical factors to serving a 30+ trillion cubic feet (TCF) market, rather than conduct a comprehensive analysis and detailed review of all aspects of the North American transmission and distribution sectors as was undertaken in the NPC's 1992 study on natural gas (hereinafter referred to as "the 1992 Study").

Modeling Framework

The GRI Hydrocarbon Supply Model (HSM) was developed by Energy and Environmental Analysis, Inc. (EEA) for the Gas Research Institute (GRI) in the mid-1980s and was used to investigate gas supply issues for the 1992 Study. The GRI Hydrocarbon Supply Model is a PC-based analytical framework designed for the simulation, forecasting, and analysis of natural gas, crude oil, and natural gas liquids supply and cost trends in the United States and Canada. The HSM, along with the gas transmission and demand components of EEA's Gas Market Data and Forecasting System (STM) were chosen as the modeling systems for this study. The repeat use of the HSM for the 1999 Study allowed the Supply Task Group to start its analysis using the same assumptions contained in the 1992 Study. Starting with these assumptions, a series of successive "Strawman" cases were developed in which various new assumptions were tested and adopted until the final "Reference Case" was reached. Transmission and distribution facilities were added using the STM model to bring the new and incremental supply found in the "Reference Case" to the incremental demand generated. The STM model solves for monthly gas production, storage activity, pipeline flows, end-use consumption and prices. The model helped determine the new pipeline and storage infrastructure that would be economically justified by the market conditions and assumptions in the Reference Case and each of the sensitivities.

Sensitivities

Seven sensitivities are analyzed in the Transmission & Distribution Task Group Report. These are shown in Table T-1. More detailed definitions of the sensitivities are included in the Demand and the Supply Task Group Reports. In addition, a High Pipeline Cost Sensitivity was run where pipeline cost was increased by 30% over the forecast period of 2015. It was run to mimic regulatory delay along with eminent domain and access problems. Because there were not any significant differences in pipeline mileage or city gate prices with the Reference Case, it was dropped in favor of using the other sensitivities.

Transmission & Distribution Task Group Key Assumptions

The economic, exogenous oil price, end-use demand, electricity demand, and power generation assumptions are covered separately in the Demand and the Supply Task Group Reports. Key assumptions made by the Transmission & Distribution Task Group are as follows:

- **Liquefied Natural Gas (LNG) Imports.** Lower-48 LNG imports grow to 780 billion cubic feet (BCF) by 2015. The existing re-gasification capability of the four existing LNG terminals was assumed to be utilized at up to 75% of its maximum capacity and capped at that level on an annual basis. These import terminals are located at Everett, MA, Cove Point, MD, Elba Island, GA, and Lake Charles, LA. New LNG import terminals are not built during the forecast period, but the existing terminals may need to be enhanced to perform at these levels toward the end of the forecast period.
- **Productivity Improvement.** A productivity improvement factor is included for both Transmission (pipelines) and Distribution and is 1.0% annually.
- **Pipeline Capital Structure.** The capital structure for all new pipelines and expansions of existing pipelines is 60% debt and 40% equity.
- **Transmission Pipeline Costs and Expansion Costs.** Generic pipeline capacity is built in the model when it is economically justified, that is, when the regional cost basis (marginal value)

TABLE T-1

KEY CHANGES IN SENSITIVITIES ANALYZED IN 1999 STUDY

Sensitivity	Key Change
Higher Oil Price	Increased WTI oil prices to $22.00
Lower Oil Price	Decreased WTI oil prices to $15.00
Higher GDP Growth	Increased annual U.S. GDP growth to 3%
Lower GDP Growth	Decreased annual U.S. GDP growth to 2%
Faster Technology Advancement	Acceleration of supply technology improvements
Slower Technology Advancement	50% of 1999–2015 supply technology gains in Reference Case
Larger Resource Base	Additional 250 TCF Reserves added to Reference Case

between receipt and delivery node exceeds the cost of new pipeline development. It was assumed that this basis must exceed the cost-of-service of an expansion by 20% for three consecutive years before the capacity would be placed in-service. The expansion costs used were based on historical costs of projects as reported in the *Oil and Gas Journal*. The base capital cost for new pipe is $1.68 per thousand cubic feet per day (MCF/D) per mile. This was less expensive than what was used in the 1992 Study and is an indication that pipeline costs are declining on a real basis. Regional multipliers to reflect differences in costs to build are shown in Table T-2. To determine regional capital cost per MCF/D per mile, the base capital cost of $1.68 is multiplied by each regional multiplier.

TABLE T-2

REGIONAL MULTIPLIERS

Region	Regional Cost Multiplier
Northeast	1.4
Southeast	0.9
East South Central	1.1
Midwest	1.3
Plains	1.0
West South Central	0.9
Rockies	1.1
Pacific	1.3
Offshore	1.2
Canada	0.8
Mackenzie Delta	1.6

- **Storage Expansion Costs.** Like pipeline capacity, storage capacity is built when it is economically justified. Expansion costs were based on analysis by EEA of historical storage expansions. The capital cost of new storage ranges between $3 million and $6 million per BCF. Seasonal price spreads (dollars per million British thermal units (MMBtu)) justifying new storage are shown in Table T-3. Only areas where the geology is favorable can have storage built.

TABLE T-3

SEASONAL PRICE SPREADS (Depleted Field Storage Only)

Region	Expansion Costs per MMBtu
New York and Eastern Canada	$2.00
Pennsylvania	$1.80
Ohio and West Virginia	$1.60
Midwest	$1.40
Producing Area	$1.20
Rocky Mountains and West	$1.60

- **Transmission and Distribution Unit Revenues.** The economic equilibrium process of the model has transmission unit revenues moving toward the marginal cost (value) of transmission over time. Also, shippers become less willing to pay contractual premiums (revenue in excess of the marginal value). The historical 1995–97 average contractual premium of $7.5 billion shrinks to $4.8 billion in 2015. In real terms, per-unit distribution revenues are assumed to decline over time as efficiency gains and the competitive drive toward marginal cost are considered.

Background

Prior to the 1990s, nearly all natural gas flowing in the interstate market was owned by the major pipeline companies, which transported and sold the gas to their customers that were primarily LDCs. The regulatory changes by the Federal Energy Regulatory Commission (FERC), starting with Order 436 in 1985 and culminating in Order 636 in 1993, changed everything from the roles and obligations of the participants, procurement practices, and customer relationships, to operations and services of the delivery system. FERC Order 436 required interstate pipelines to transport gas owned by others on a non-discriminatory, first-come, first-serve basis. But this did not prove adequate to foster efficient price signals and the complete unbundling of services. In 1992, FERC issued Order 636, which changed the fundamental structure of the industry. With this order, interstate pipelines exited the gas sales business and thus became strictly transporters of gas owned by third parties offering unbundled transmission and storage services. Another key aspect of Order 636 was the capacity release provisions that allow firm capacity owners to assign their capacity rights to others, either temporarily or permanently, subject to various conditions. These initiatives and emerging market forces created open-access transportation on the interstate pipeline system and provided increasing flexibility in the way the industry operates. They have also allowed for many new entrants such as marketers to offer services.

From 1990 through 1998, natural gas consumption in the United States increased by 14% and pipeline deliverability increased sharply in response to the increased demand and changes in supply sources. At least 17 new interstate pipeline systems have been constructed since 1990, adding more than 8 billion cubic feet per day (BCF/D) of capacity by the end of 1998.[1] In addition, several pipeline expansions have been completed to bring greater flows from Canada. In the early 1990s, three geographic regions were the primary focus of capacity expansion: the Western, Midwest, and Northeast regions. All three regions shared a common element, greater access to Canadian supplies. In addition, the Western Region had expansions out of the San Juan Basin of New Mexico. The greatest increase in capacity since 1990 occurred on those routes between Canada and the U.S. Northeast, 1.9 BCF/D.[2] The largest increase in purely domestic capacity, however, was between the Southwestern and Southeastern states, 1.1 BCF/D.[3] This increase was driven primarily by the growth

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[1] Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity and Natural Gas Proposed Pipeline Construction Database, as of December 1998.

[2] Department of Energy (DOE/EIA-0560(98)) *Natural Gas 1998 Issues and Trends,* p. 112.

[3] Ibid.

in electric power and industrial demand for natural gas in the Southeast, particularly in Florida. In regard to storage, development of additional storage capacity has slowed since 1993, the decade's peak year for storage development. In that year, about 103 BCF of working gas capacity and nearly 4 BCF/D of deliverability were added. The years since then have seen a significant drop in expansion activities. The development slowdown includes salt cavern storage. Although there has been a slowdown in storage development activity and a recent slight reduction in working gas capacity from 3,793 BCF in 1990 to 3,724 BCF in 1998, storage deliverability is up at least 20% during this period.[4] In fact, the current transmission and storage system is capable of meeting its existing firm requirement contracts on an annual, seasonal, and peak-day basis.

Today, the interstate pipeline system is a national grid with sufficient flexibility to move gas in many directions as markets and economics dictate. The largest flows of natural gas are from the Southwest to the Midwest and along the East Coast (see Figure T-1). In 1998, approximately 25% of natural gas consumed in the United States was from the offshore Gulf Coast area. The onshore areas of Texas, Louisiana, New Mexico, and Oklahoma account for another 45% of total delivered supply.[5] With the expansions of the TransCanada pipeline systems, gas imported from Canada, which accounted for less than 8% of total U.S. consumption in 1990, has grown to about 14% of total U.S. consumption.[6] Imports from Canada primarily serve the Pacific, Midwestern, and Northeast markets and are projected in this study to increase from 3 TCF in 1998 to over 4 TCF by 2015, continuing to represent about 14% of the delivered supply to meet U.S. demand.

Natural gas consumption is expected to grow steadily into the next century, with this study projecting annual average demand to be 32 TCF or 87 BCF/D by 2015 and peak-day requirements of approximately 152 BCF/D. The prospect of a large increase in annual average and peak-day demand and the shifts in supply locations to the deepwater Gulf of Mexico, Rockies, western Canada, and the Canadian Atlantic regions has significant implications for the natural gas delivery system. Key questions are what kinds of infrastructure (transmission, storage, and distribution) changes and what level of investment will be required to serve such a market. In addition, there will be challenges: obtaining access to rights-of-way, providing new flexible services, and adapting to changing risks to attract capital.

There will be additional pressure on obtaining access resulting from population growth. Population in the United States has been growing at a rate of about 1.1% in the 1990s. Even though this is expected to slow to 0.5% in the next century, population in the United States by 2015 will increase by nearly 40 million. Population growth, and the attendant urban sprawl, combined with greater environmental awareness have resulted in more "Not In My Back Yard" (NIMBY) behavior and more restrictive environmental regulations. Public protest to recently proposed pipeline projects from the Midwest to serve Northeast markets has delayed their regulatory approval by FERC.

Since natural gas is the cleanest fossil fuel, the greater environmental awareness is helping drive the demand for gas-fired electricity generation along with favorable economics and the restructuring of the electric industry. Since 1990, yearly consumption of natural gas for use in generation of electricity has varied from 2.7 to 3.2 TCF, down from the 3.9 TCF in the early 1970s. But, now the future of natural gas is expected to be closely tied to electricity generation, with consumption in that sector projected in this study to increase to 7.8 TCF in 2015. The physical and operational aspects of new gas-fired generation combined with the large growth in this load will have major implications for the natural gas delivery system infrastructure and the need for new flexible services.

As a result of the natural gas industry restructuring, now almost all natural gas is purchased directly by marketers and large end-users from producers in an open market with the interstate pipeline and LDCs

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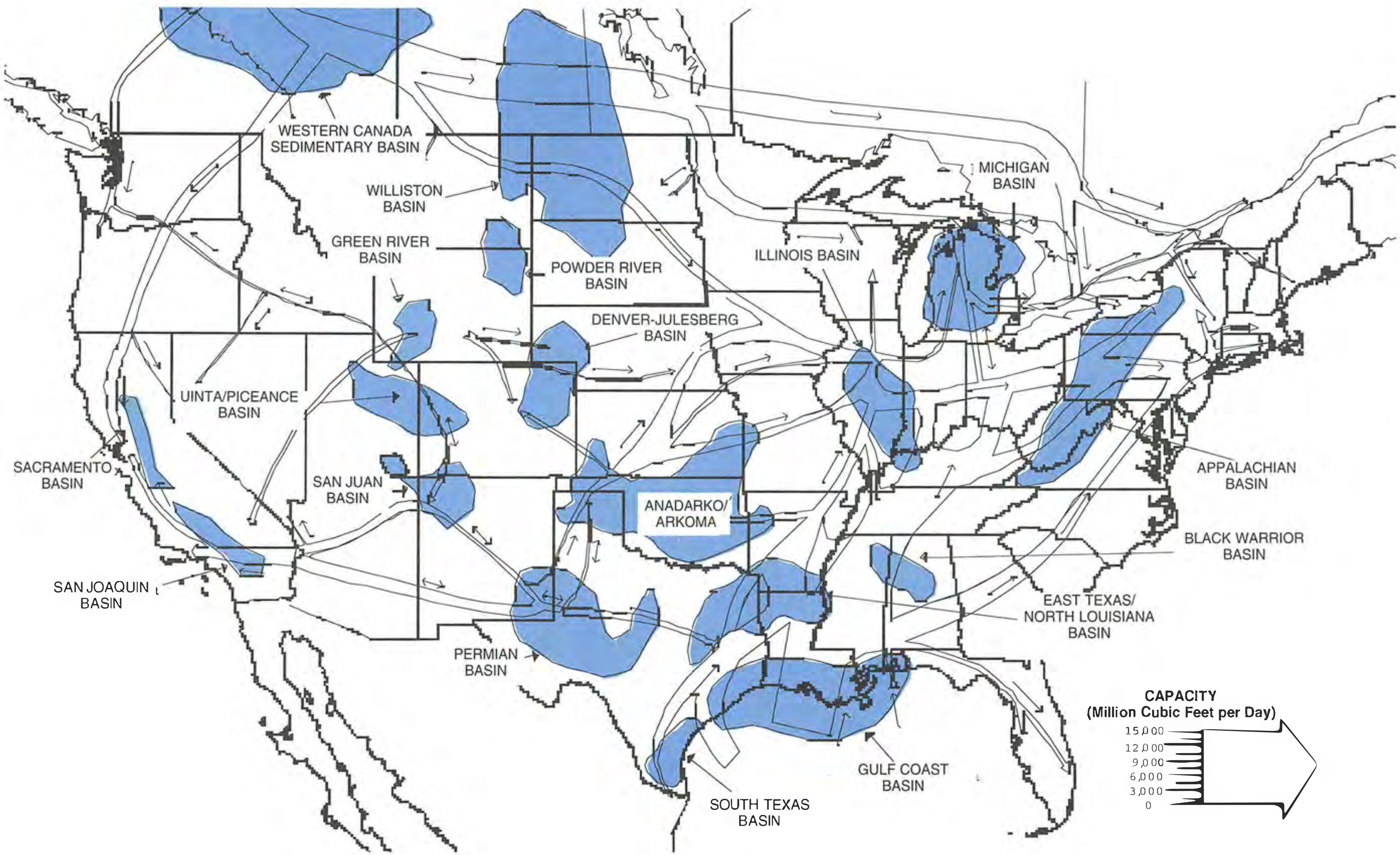
[4] Energy Information Administration.

[5] Energy Information Administration, *Natural Gas Annual*, 1998.

[6] Energy Information Administration, *Natural Gas Monthly*, August 1999.

Figure T-1. Major Natural Gas Producing Basins and Transportation Routes to Market Areas



Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of December 1997.

principally providing transportation services for these customers. However, most residential and commercial customers still purchase their gas supplies via bundled services provided by their LDCs. The greater access to transportation services, the growth in new services and pipeline routings, and greater participation in the market by end-users, marketers, and others has resulted in a much more competitive natural gas delivery system than existed a decade ago. Along with increased competition, the industry restructuring has led to new and changing risks and uncertainty for all industry participants.

The following chapters will present the results from the Transmission & Distribution Task Group's analysis and an examination of the challenges for these segments of the industry as they look forward to fulfilling their potential toward meeting the environmental and energy needs of the nation.

Chapter One

Significant Expansion and Enhancements to the Delivery System are Required to Serve the Growing Demand

Substantial changes are expected in natural gas supply and consumption patterns by the year 2015. These anticipated changes create a need for enhancements to the existing delivery system and construction of new transmission and storage facilities. The consumption of natural gas in the United States peaked in 1972 at 22.1 TCF. Since then, geographic shifts in supply and demand (such as the decline of the industrial Midwest and increases in supply from the Rockies and Canada) have caused the interstate transmission and storage system to expand more slowly than otherwise expected (Figures T-2 and T-3). Today there are more than 270,000 miles of gas transmission pipelines and approximately 3.8 TCF of working gas storage capacity. The U.S. delivery system also includes another 952,000 miles of gas distribution mainlines ("mains").

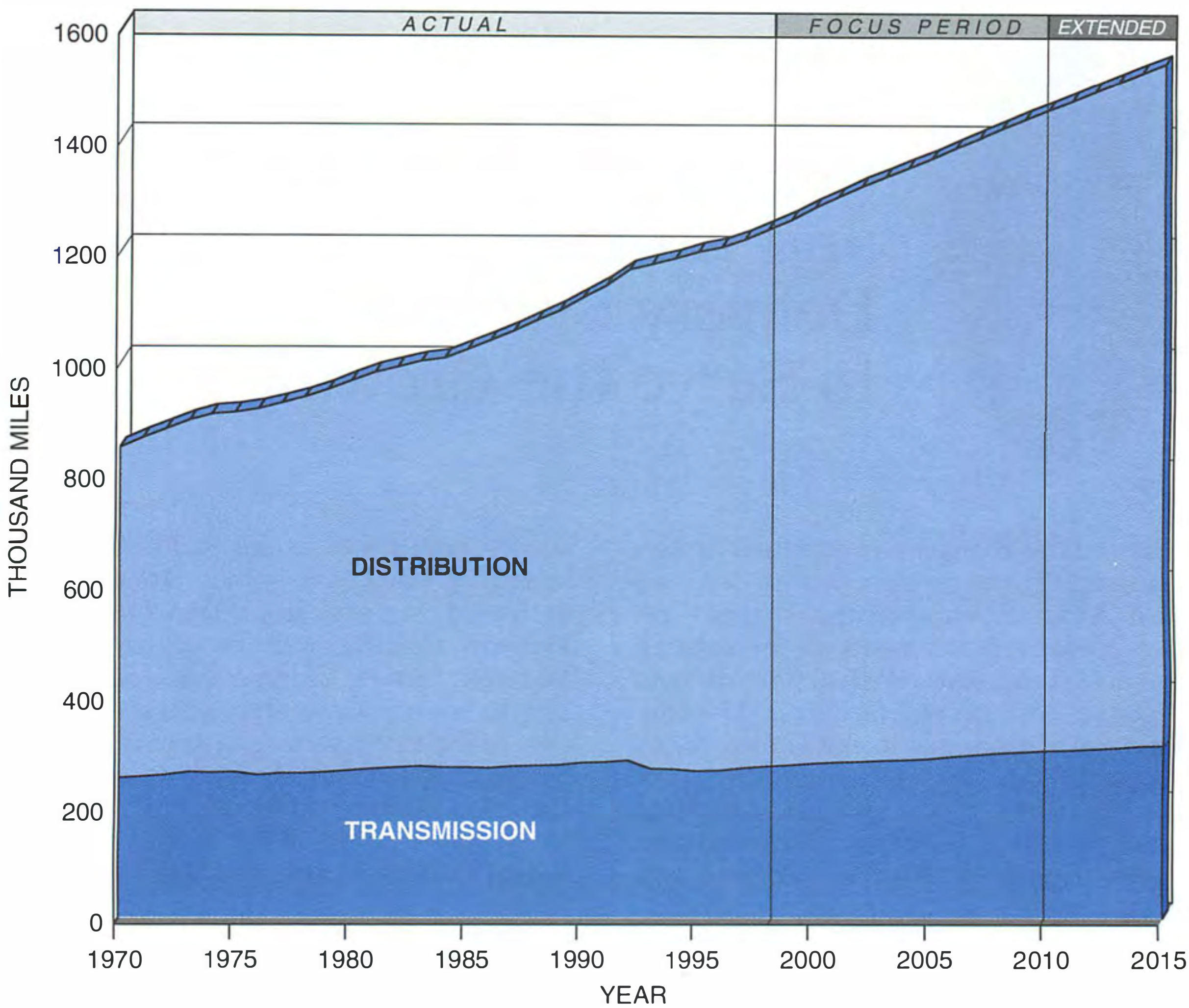
Transmission Facilities Analysis

Two shifts in the flows on the interstate transmission grid have developed recently. First, there has been a significant decrease in Gulf Coast and Mid-Continent supply moving to the Midwest (i.e., Chicago area). This shift has been caused by slow market growth in the Midwest and displacement of Gulf Coast and Mid-Continent supply by Rockies and Western Canadian production as additional pipeline infrastructure has come on line. Second, a significant amount of Gulf Coast supply now flows to the Southeast to meet increased market demand. In the future, increased supply from the Rockies and Western Canada will be flowing to the Midwest, turning Chicago into a supply hub. The Reference Case shows that significant new or incremental transmission capacity will be built from the Rockies to California, Canadian Atlantic to New England, Gulf of Mexico to Florida, Western Canada to the Pacific Northwest, and the Mackenzie Delta to Alberta.

A significant investment in delivery system facilities will be necessary to meet the new demand requirements and the shift in supply locations to the deepwater Gulf of Mexico, Rockies, western Canada, and Canadian Atlantic regions. Although the level of investment is significant, it is unlikely to pose a constraint on reaching the anticipated 31 TCF market. As shown in Figure T-4, the forecasted average annual capital expenditures of $2.5 billion per year for transmission and storage facilities are slightly less than the average annual capital expenditures during the last three decades.

Historical and projected annual U.S. capital expenditures for natural gas transmission are shown in Figure T-5. The sawtooth pattern is normal and reflects capital expenditures when pipeline construction makes economic sense. Pipeline construction is cyclical and in the STM model generally follows the

Figure T-2. U.S. Natural Gas Pipeline Cumulative Mileage



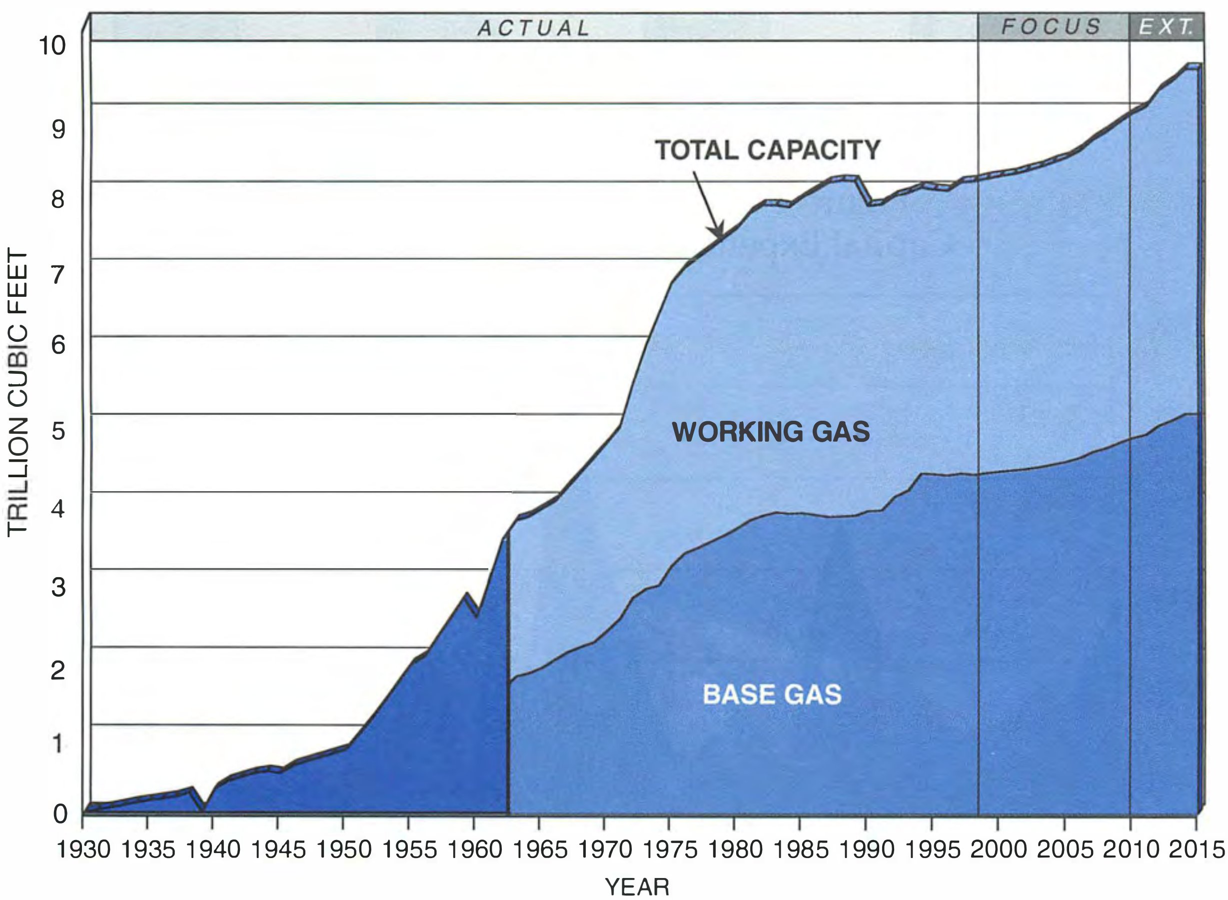
Source of historical data: American Gas Association, *1998 Gas Facts.*

pattern of "basis" differentials between source and delivery nodes. The historical data were obtained from *Gas Facts*, an annual publication from the American Gas Association (AGA), and are presented in 1998 dollars. In the 1970s, annual expenditures averaged $2.7 billion. Expenditures were flat during the 1980s, but increased to $3.3 billion annually from 1990 through 1997. This increase in expenditures from the late 1980s to the mid-1990s tracked the rebound in U.S. natural gas consumption. Many of the expenditures in this period were for projects designed to increase U.S. access to Canadian gas (Great Lakes expansion, Iroquois, Northern Border expansion, Niagara, and the Pacific Gas Transmission expansion).

The total capital expenditures in the Reference Case for U.S. gas transmission infrastructure, stated in 1998 dollars from 1999 to 2010, are projected to be $29.1 billion in the Reference Case. Total capital expenditures include new pipeline projects, pipeline expansions, replacement projects, and new storage projects. After 2010, the uncertainties in assumptions begin to escalate, making it difficult to determine an exact level of capital expenditures. From 1999 to 2015, total capital expenditures range from $33.6 billion to $43.7 billion across the seven sensitivities. A total of $43.7 billion is spent in the Higher GDP Growth sensitivity. The lowest capital spending of $33.6 billion occurs in the Lower Oil Price sensitivity. These two sensitivities are displayed in Figure T-6. The projected annual average ranges from $2.0 to $2.6 billion. This is significantly lower than the historical average capital expenditure of about $3 billion in 1998 dollars over the last 15 years. This decrease is attributable in part to the assumption that there will be an annual 1% productivity improvement. However, the major reason is due to the efficient way the STM model adds pipelines. The model only builds pipeline capacity when the basis justifies it. Over-building due to competitive reasons is not factored into the analysis. During the partial deregulation of the 1990s, building pipelines has become a more competitive business. It is often the case that pipelines are designed to allow for cost-effective expansion of the system in the future. Also, many projects have been built where the basis did not initially justify their construction. This has contributed to the marked increase in capital expenditures in recent years. If this trend continues, future average capital expenditures will be higher than projected in the model results.

It is projected that pipeline projects to import Canadian supplies and increased pipeline infrastructure in the Midwest will account for the greatest expenditures through

Figure T-3. Underground Natural Gas Storage Capacity



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

Sources: Total Capacity: American Gas Association, Engineering Technical Note, *Underground Storage in the U.S. and Canada–1990,* April 1991.
Base Gas: Energy Information Administration, *Annual Energy Review 1990,* p. 175.
Working Gas = Total minus Base.

Figure T-4. Average Annual Historical and Projected Transmission and Storage Capital Expenditures for Lower-48 States

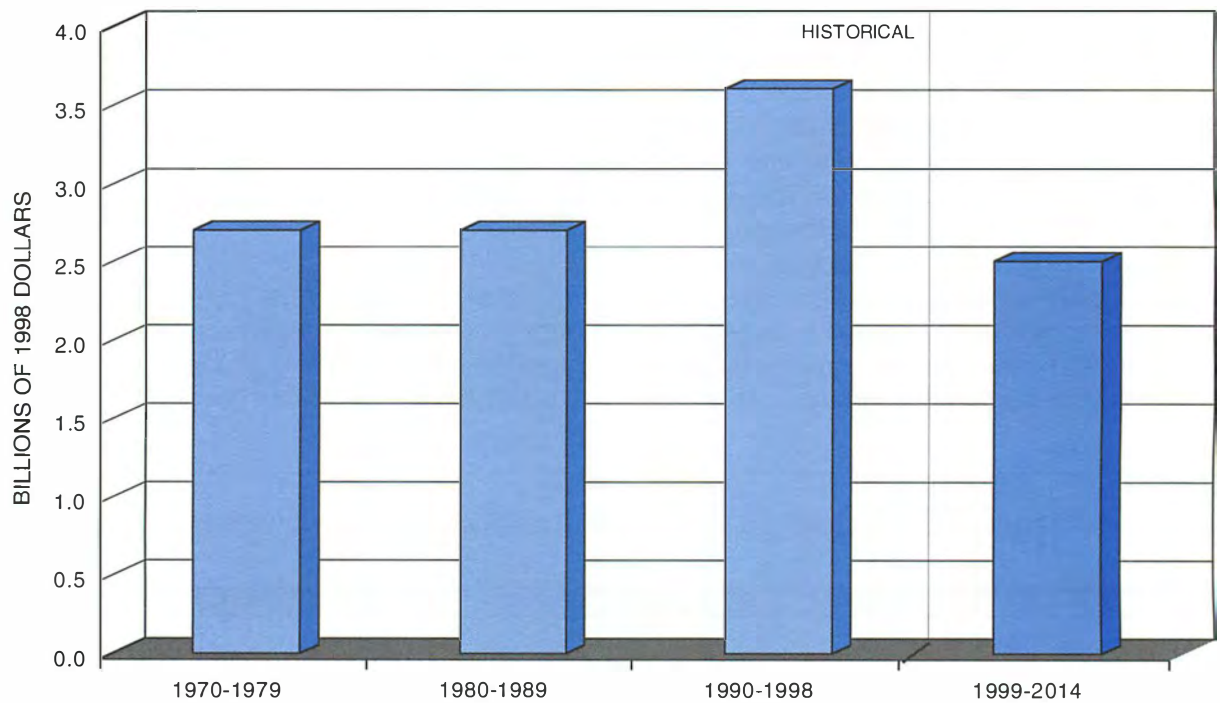
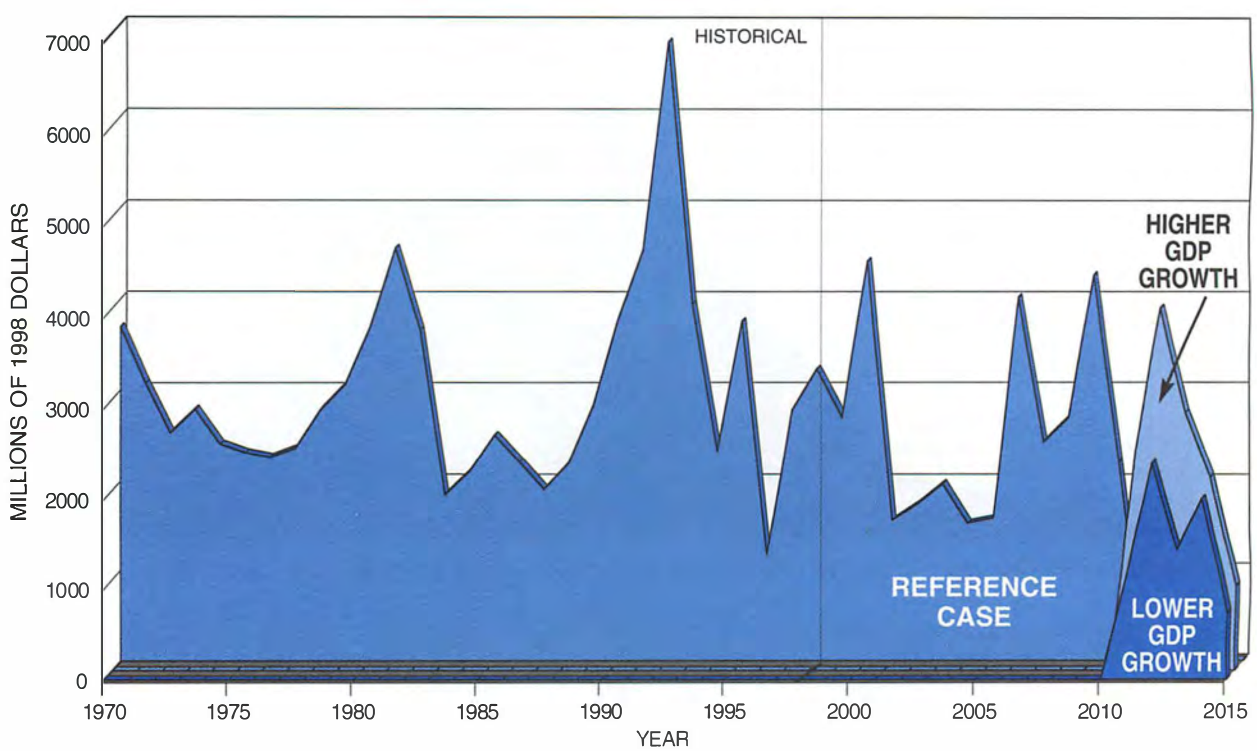
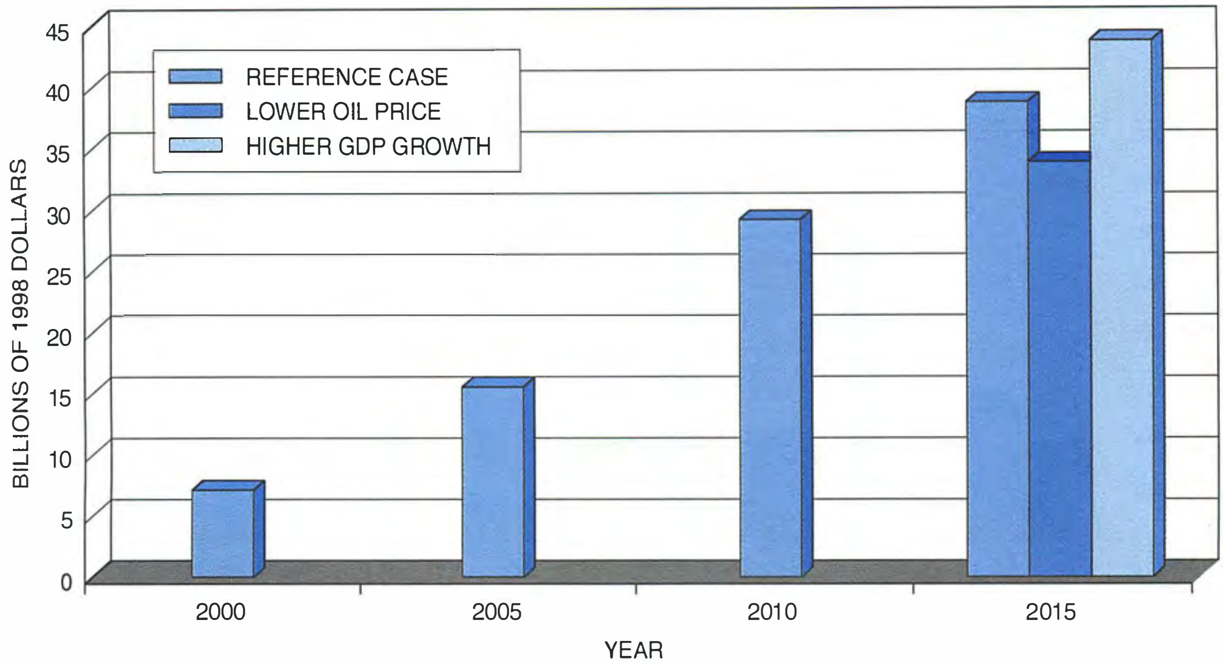


Figure T-5. Historical and Projected Capital Expenditures for Lower-48 States



Source of historical data for Figures T-4 and T-5: American Gas Association, *1998 Gas Facts*.

Figure T-6. Cumulative New Pipeline Capital Cost (including replacement) for Lower-48 States



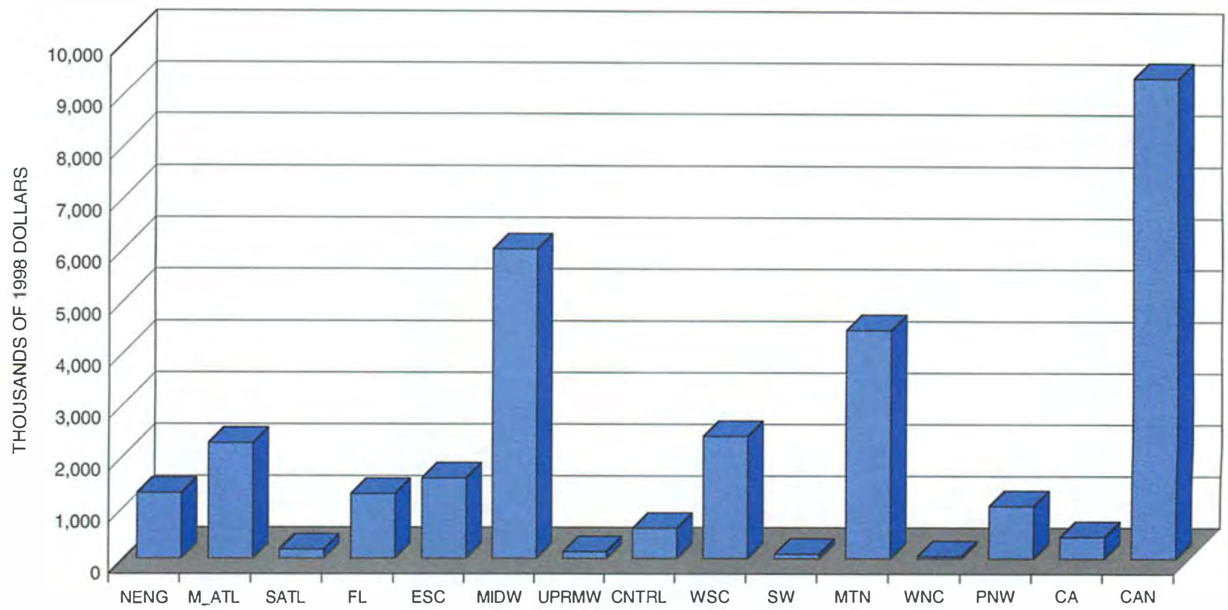
2010, as is shown in Figure T-7. Cumulative pipeline cost for the Canadian and Midwest regions are $9.3 billion and $6.0 billion, respectively. In all of the sensitivities, spending in the Rockies supply region increases significantly such that it nearly equals or passes the Midwest to become the area with the second greatest capital expenditures through 2015. An example of this is shown in Figure T-8. For a geographical depiction of the regions used in the STM model, see Figure T-9.

There is no easy way of summarizing into a single statistic the "capacity" of the entire U.S. gas pipeline infrastructure. The ability to flow gas on any given day depends on where the gas is being produced or withdrawn from storage and where the gas is being consumed. As such, this study analyzes capacity from the perspective of specific interregional flows and capacities and how they might change in the future. As mentioned previously, Figure T-9 shows the different regions as defined in the STM model output. Figure T-10 shows the nodes and nodal paths used to represent the North American natural gas transmission network.

In the Reference Case and all sensitivities, significant shifts in gas supply increase flows on some pipes, but decrease flows on others. As noted previously, significant shifts in supply locations to deepwater Gulf of Mexico, Rockies, western Canada, and the Canadian Atlantic are projected. Building capacity to these frontier supply basins is the single biggest driver of pipeline costs in the scenarios. Significant shifts in gas supply require significant investment in new production-area pipe. For the purpose of this study, frontier supply is defined as deepwater Gulf of Mexico, Rockies, Mackenzie Delta, and the Canadian Atlantic. In the Reference Case, 67% of the new pipeline capacity built is from frontier supply areas.

Over 30 BCF/D of interregional pipeline capacity is projected to be built from 1998 to 2015 in the Reference Case and nearly all the sensitivities. The average lower-48 load factor is projected to rise only slightly through 2010 in the Reference Case, as can be seen in Figure T-11. This is largely due to the significant shift to frontier supply decreasing flow on some existing pipelines. The load factor in 2015 ranges from 65% in the Lower Oil Price

Figure T-7. Reference Case, Year 2010 New Long-Haul Pipeline Cost (excluding replacement) and Storage Added to Market Areas



LEGEND:

NENG	New England	MIDW	Midwest	MTN	Mountain (Rockies)
M_ATL	Mid-Atlantic	UPRMW	Upper Midwest	WNC	West North Central
SATL	South Atlantic	CNTRL	Central	PNW	Pacific Northwest
FL	Florida	WSC	West South Central	CA	California
ESC	East South Central	SW	Southwest	CAN	Canada

Figure T-8. Lower Oil Price Case, Year 2015 New Long-Haul Pipeline Cost (excluding replacement) and Storage Added to Market Areas

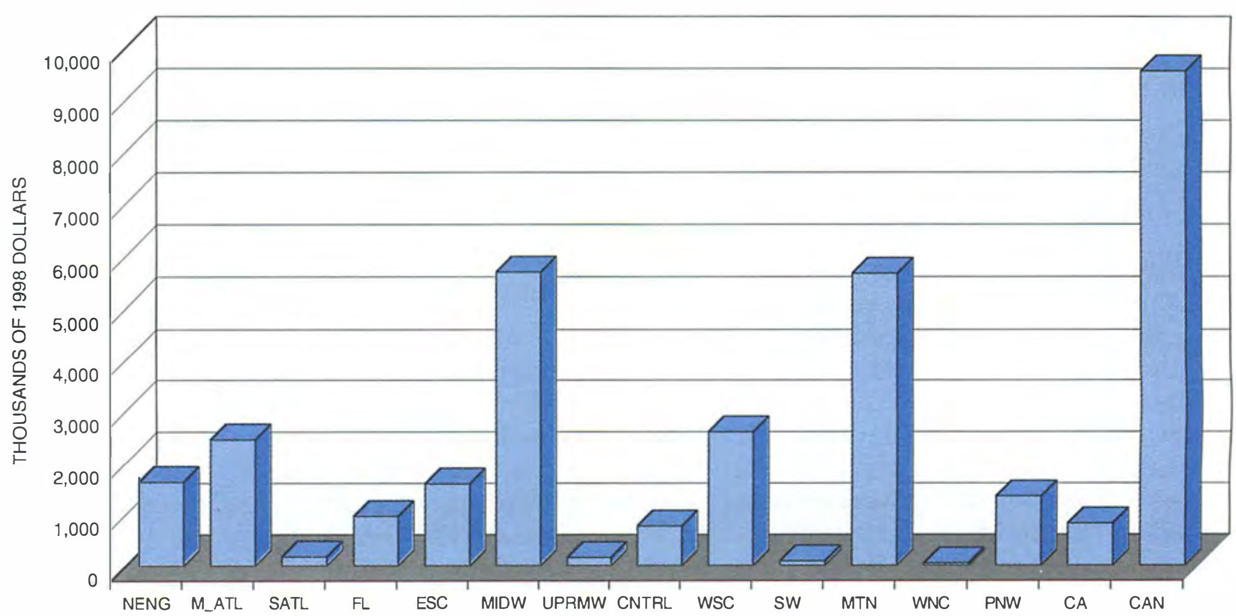
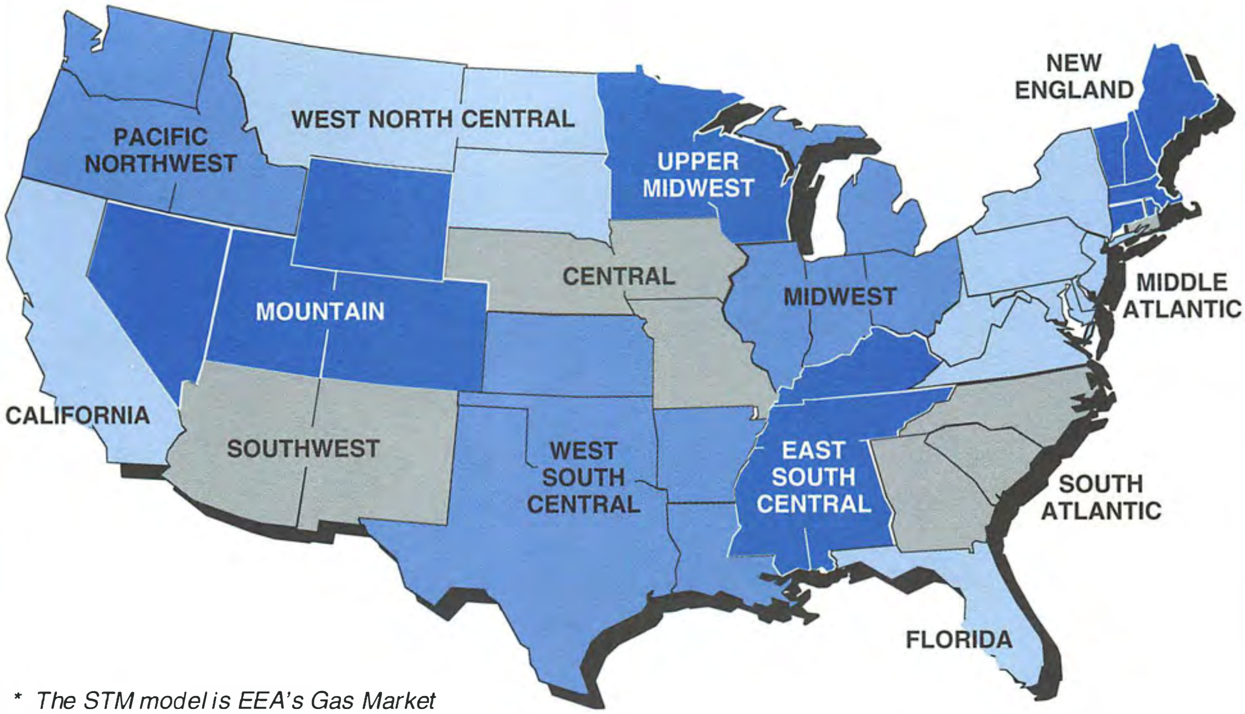


Figure T-9. STM Model* Regions



* *The STM model is EEA's Gas Market Data and Forecasting System.*

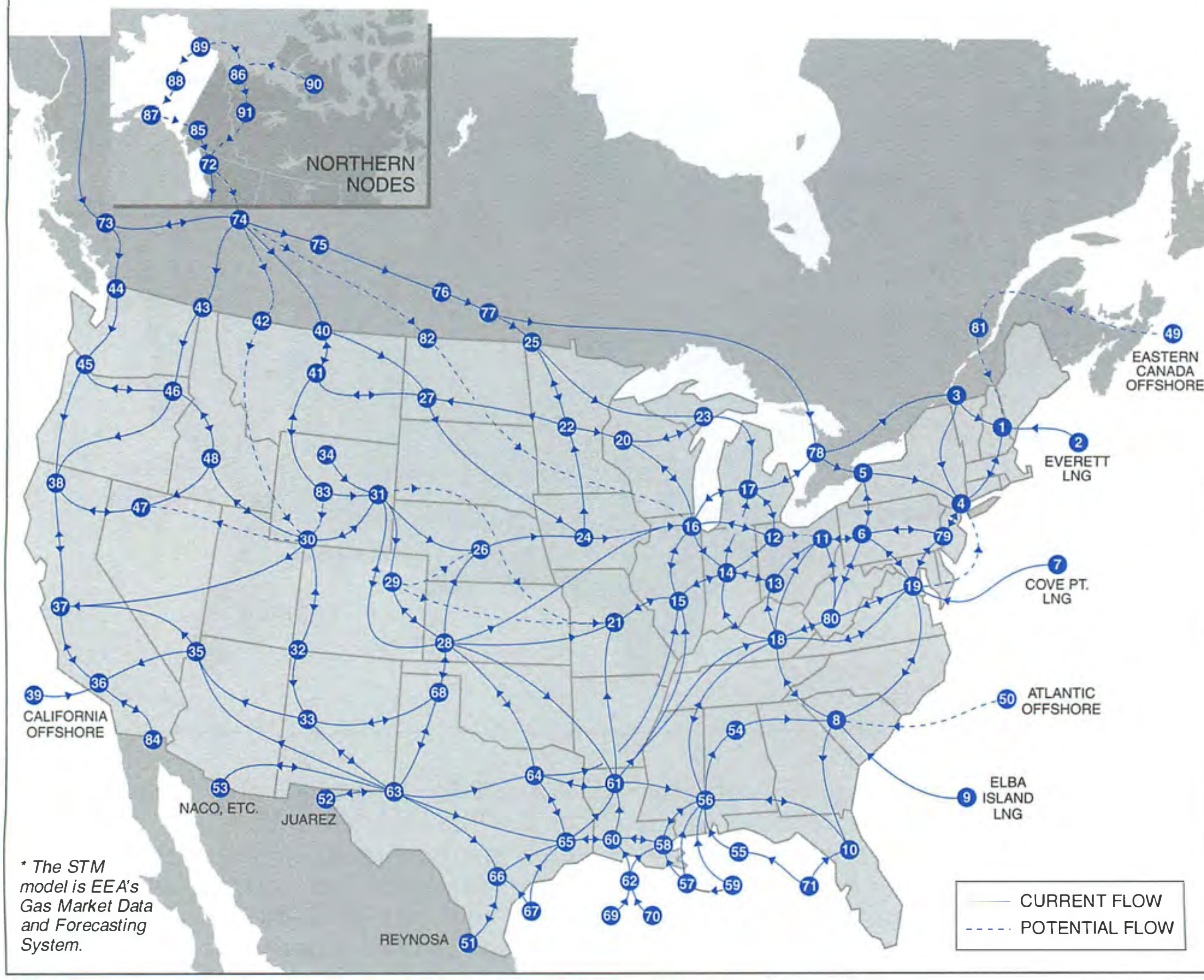
sensitivity to 72% in the Larger Resource Base sensitivity. Load factor is reduced in the Lower Oil Price sensitivity due to the production decline post-2010 in both the Gulf of Mexico and Western Canadian Sedimentary Basin and the significant increase in new capacity to the frontier regions. Load factor increases in the Larger Resource Base sensitivity since not as much new pipeline capacity is built to the frontier regions.

Net Canadian imports increase by over 50% in the Reference Case and all the sensitivities. This is shown in Figure T-12. As was mentioned earlier, the areas with the greatest expenditures of new long-haul pipe are Canada and the Midwest for projects to import Canadian gas. Canadian imports will continue to be a key factor in providing adequate supply to meet the growing demand of the lower-48 states.

Through 2015, approximately 38,000 miles of transmission pipeline is projected to be built to meet the requirements of the future market. This rate of growth is not extraordinary and is in fact comparable to the expansion experienced in the last few years, as can be seen in Figure T-13. Figure T-13 also shows the miles of pipeline expected to be constructed during each year through 2015. The sawtooth pattern is normal. Again, this reflects pipeline capacity being built only when the basis supports construction. The average annual miles, including replacement varies from a high of 2,458 miles in the Larger Resource Base sensitivity to a low of 1,856 miles in the Lower GDP Growth sensitivity. The Reference Case averages 2,366 miles through 2010. According to AGA's *Gas Facts*, there were over 3,000 miles of new gas transmission line built in both 1991 and 1992 and over 4,000 miles of new gas transmission line built in 1997. With the historical annual average from 1990 to 1997 being 2,156 miles, there is little concern that the projected increase will cause significant problems with pipeline equipment manufacturers and construction companies.

Gas prices remain volatile over the period of the study and in the Reference Case trend higher—particularly in the period beyond 2010. Since price is significantly affected by the input assumptions used by the model, sensitivity analyses were run for the key variables. This approach resulted in a

Figure T-10. STM Model* Nodal Paths



* The STM model is EEA's Gas Market Data and Forecasting System.

range of outcomes for demand and price that were both higher and lower than the Reference Case. A range of outcomes using sensitivity analyses was also developed for regional prices in order to compare with the projected Henry Hub natural gas price.

As discussed in the Demand Task Group Report, all regions show significant growth in gas demand. Interestingly, growth is fairly uniform throughout the lower-48 states. The change in the regional pattern of the production of gas in North America has the largest impact on the changes in basis. The changes in Henry Hub price versus New York City, Chicago, and Opal (Wyoming) are shown respectively in Figures T-14, T-15, and T-16. For these locations, the basis increases in all instances for the Reference Case and the sensitivities throughout this projection. Henry Hub price versus Mid-Continent and Southern California are shown in Figures T-17 and T-18, respectively. Here the basis stays relatively flat for the Reference Case and most of the sensitivities. The only notable exception is the Larger Resource Base sensitivity that shows a significant decline for the Southern California basis. The Henry Hub versus AECO (Alberta Energy Company) basis shown in Figure T-19 shows a downward trend for the Reference Case and all sensitivities. The AECO basis versus Chicago and versus Southern California shows a downward trend for the Reference Case and all sensitivities, as shown in Figures T-20 and T-21, respectively. The last basis analyzed is Opal to Southern California, shown in Figure T-22. This has an upward trend for the Reference Case and all sensitivities.

Figure T-11. Projected Interregional Pipeline Load Factor for Lower-48 States

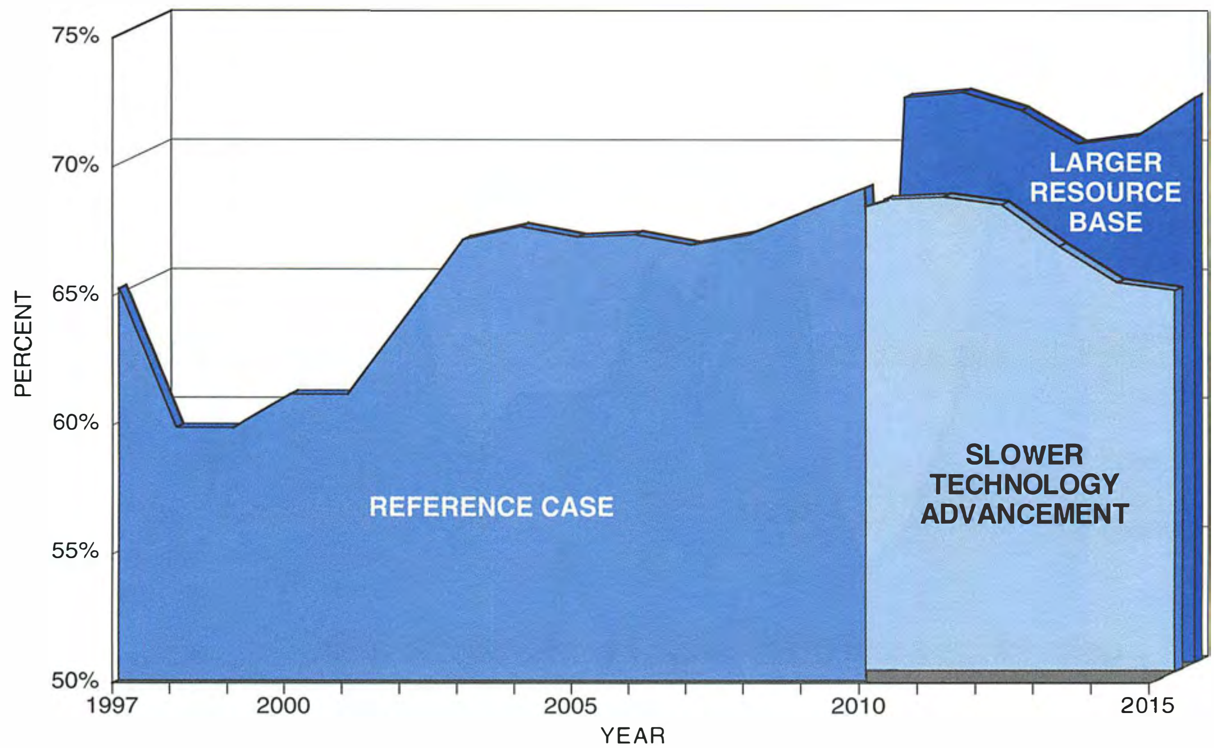


Figure T-12. Net Canadian Imports

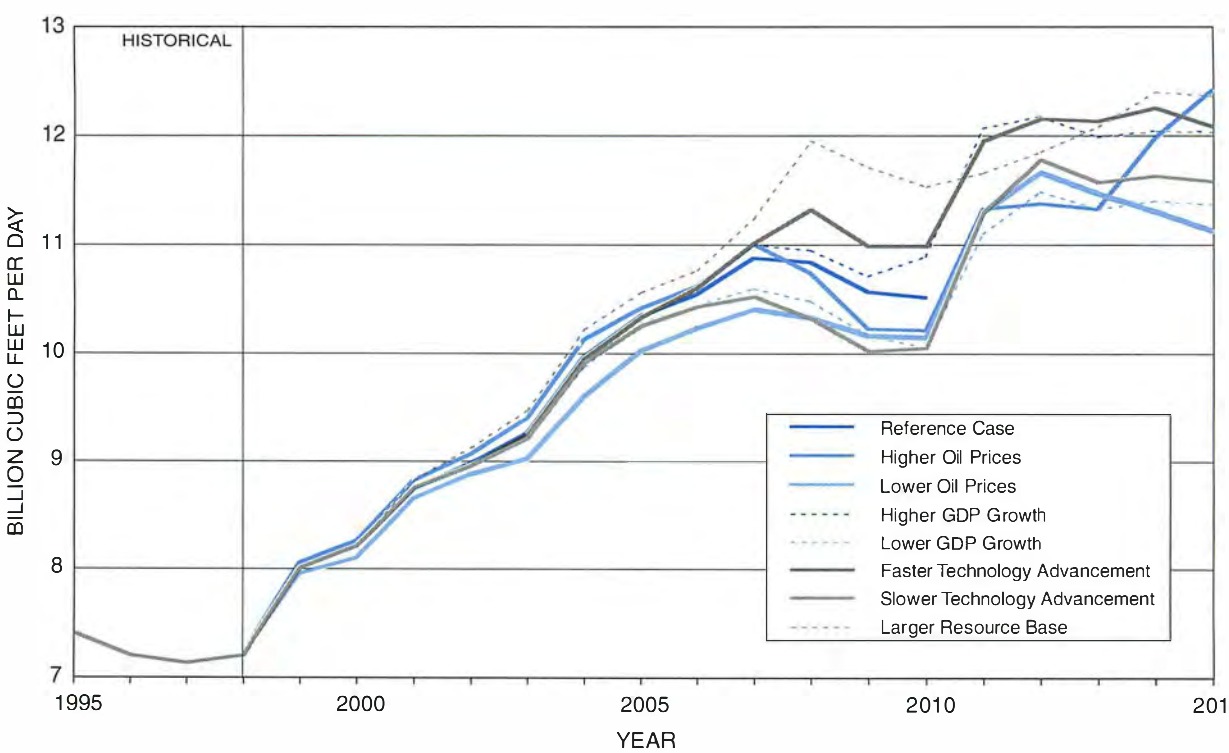


Figure T-13. Miles of Pipeline Including Replacement Constructed Each Year for Lower-48 States

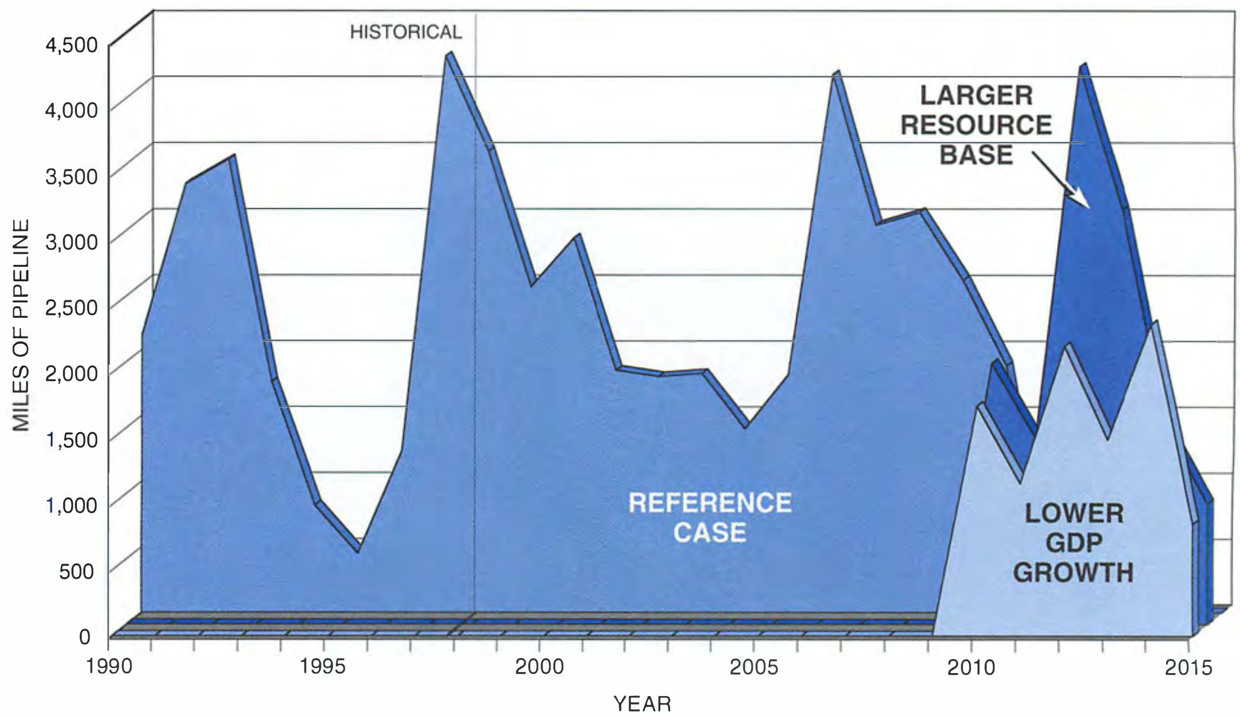


Figure T-14. Change in Henry Hub Price versus New York City

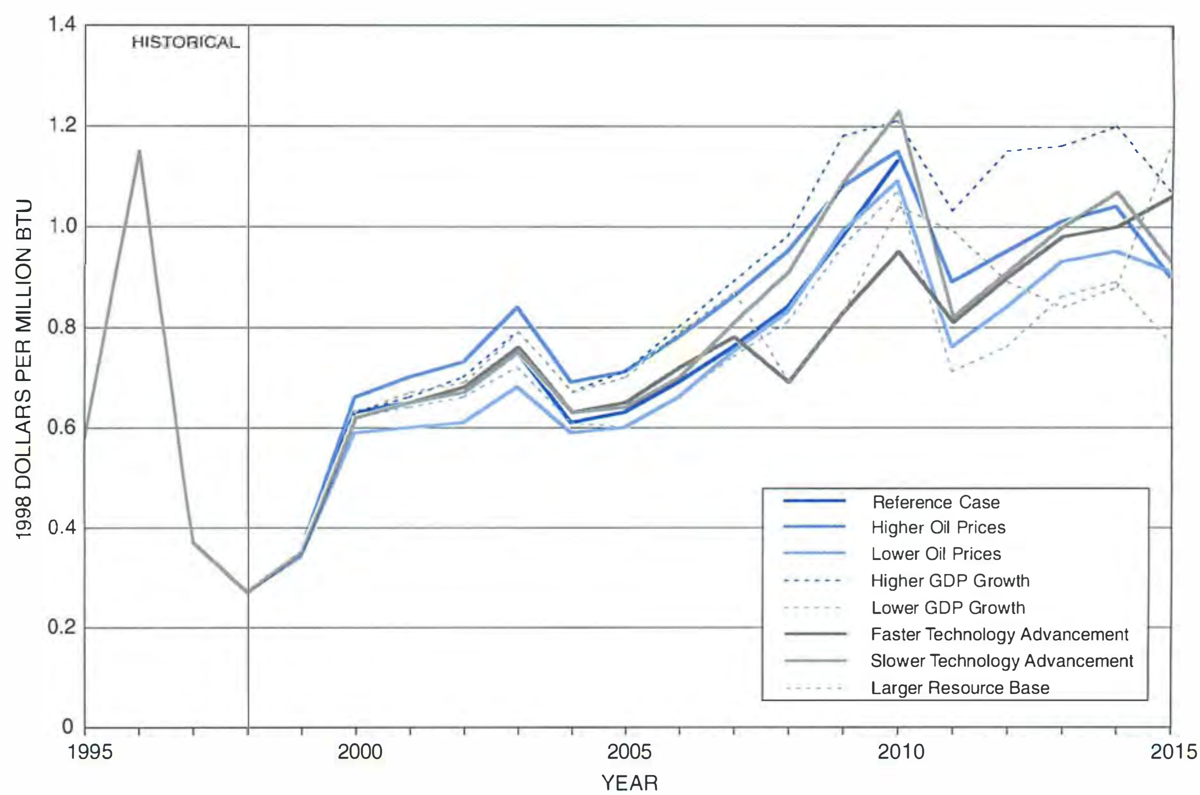


Figure T-15. Change in Henry Hub Price versus Chicago

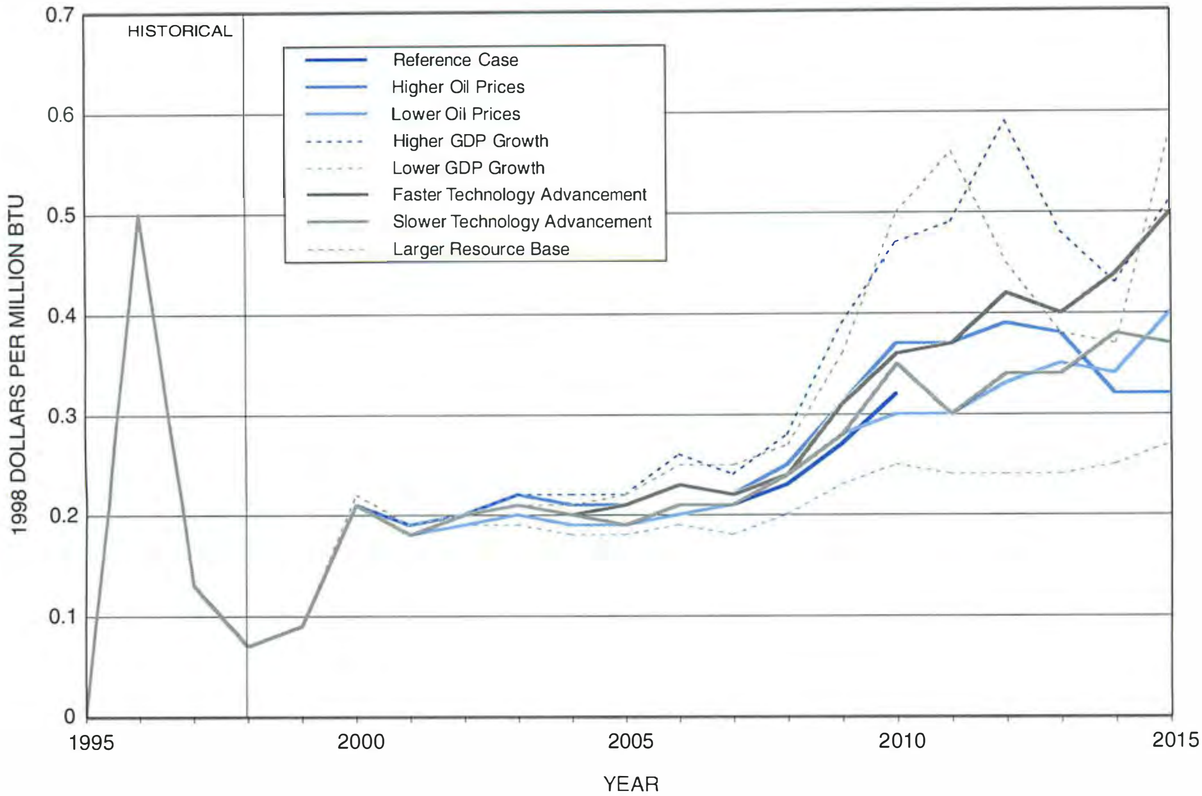


Figure T-16. Change in Henry Hub Price versus Opal

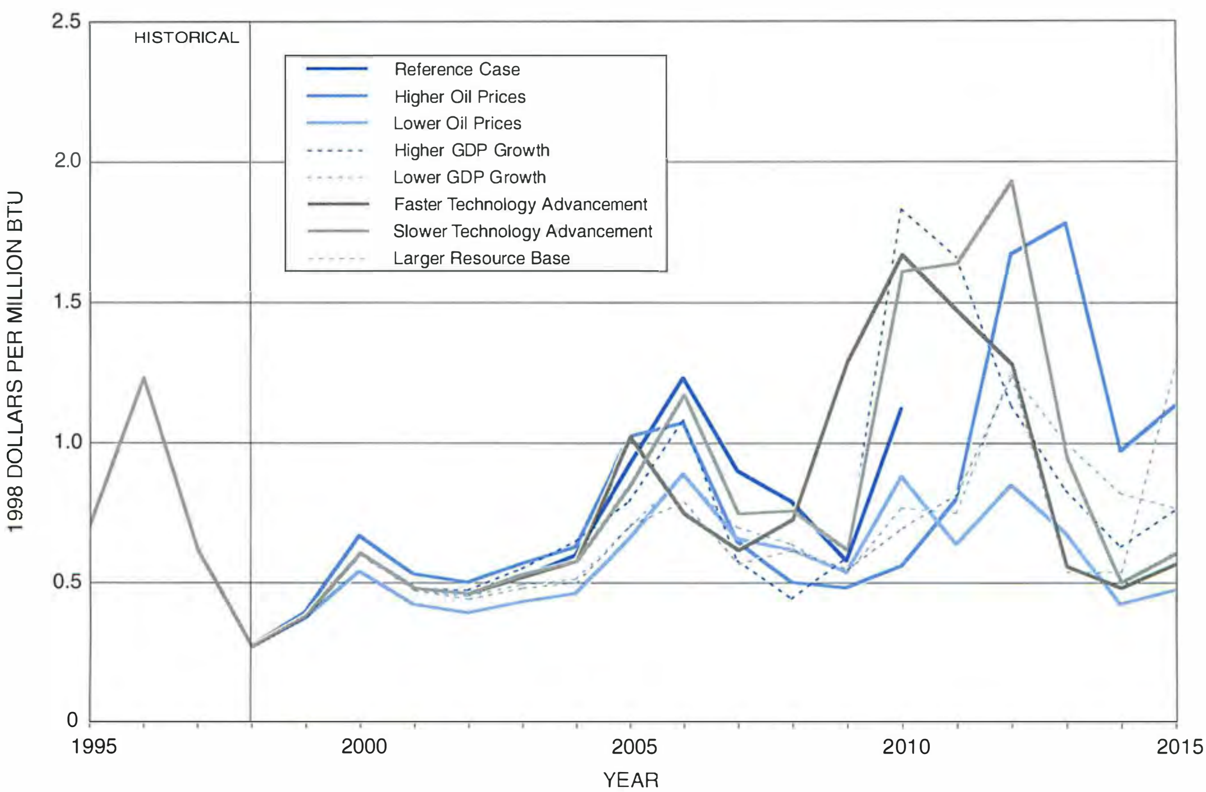


Figure T-17. Change in Henry Hub Price versus Mid-Continent

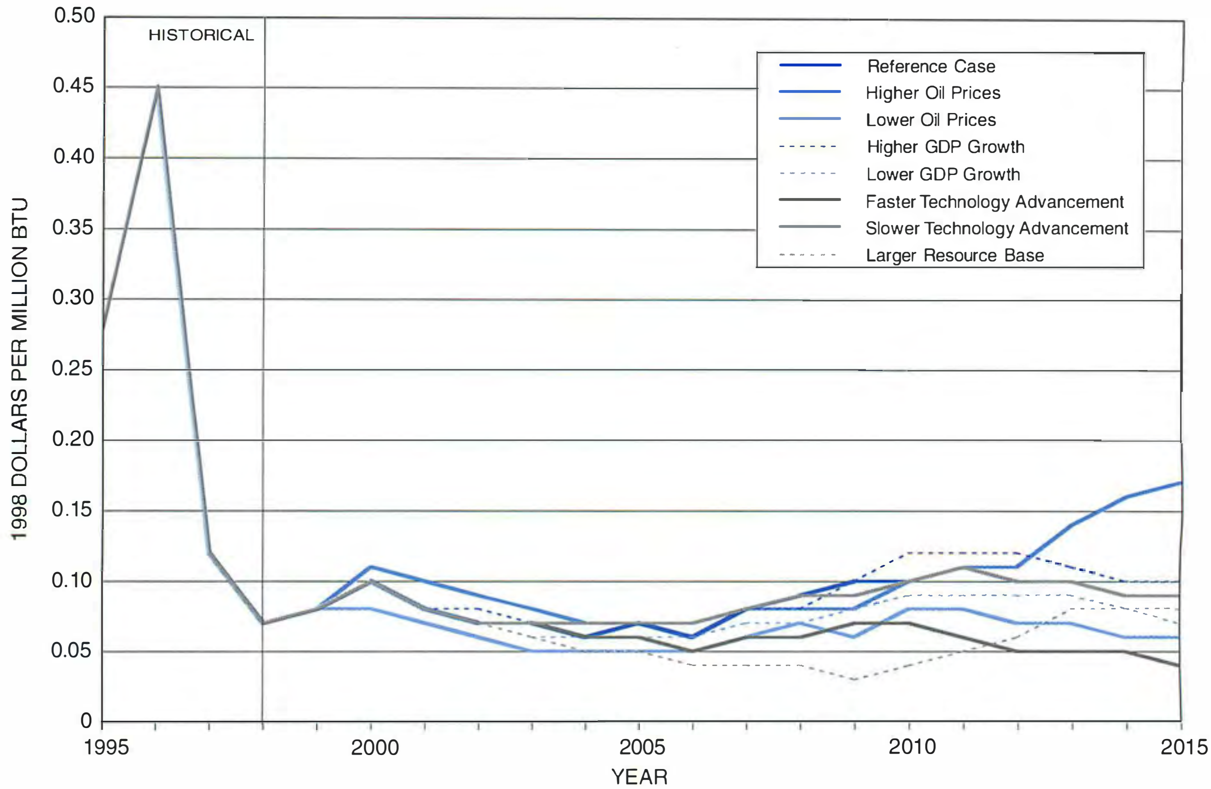


Figure T-18. Change in Henry Hub Price versus Southern California

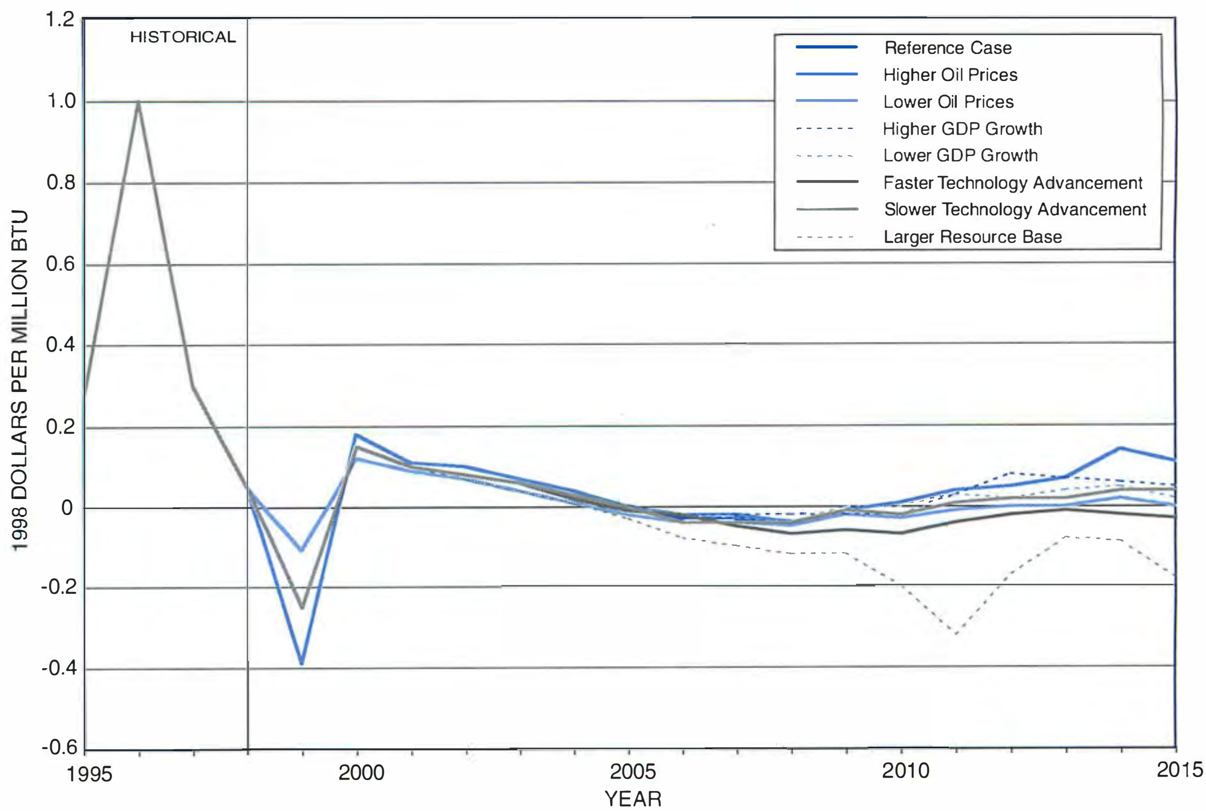


Figure T-19. Change in Henry Hub Price versus AECO

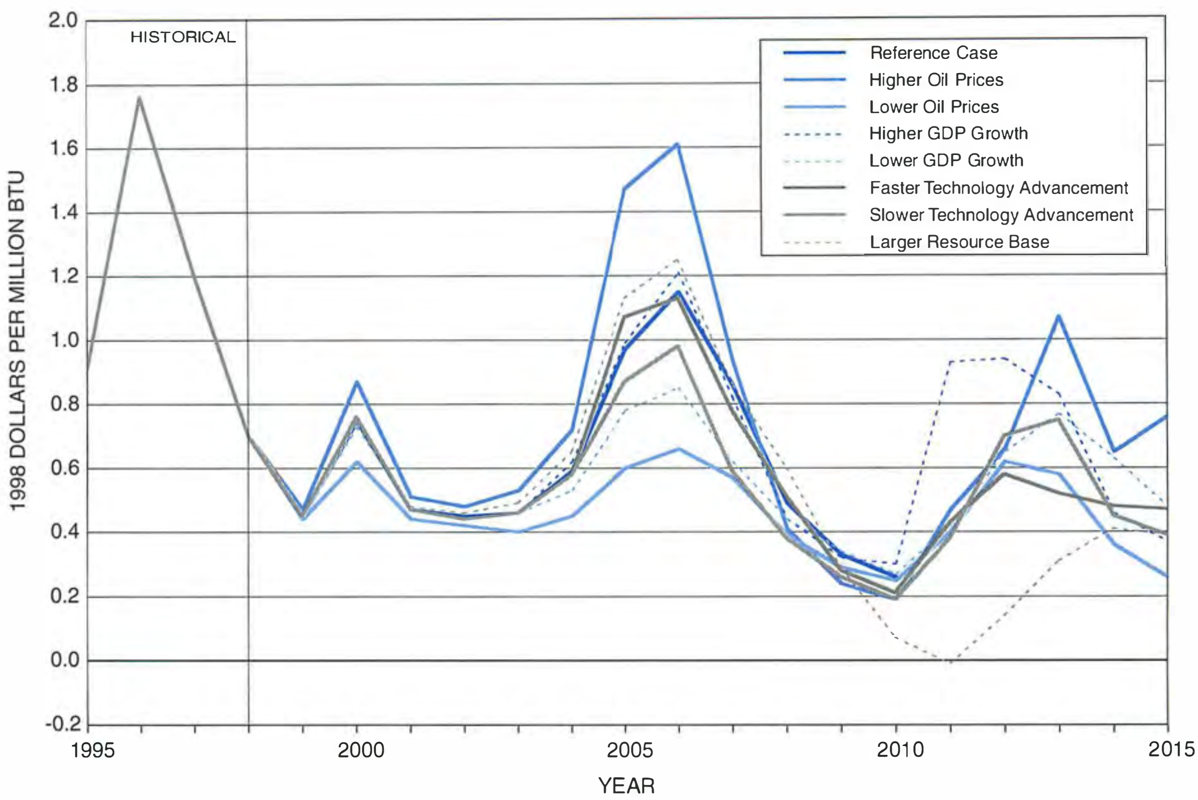


Figure T-20. Change in AECO Price versus Chicago

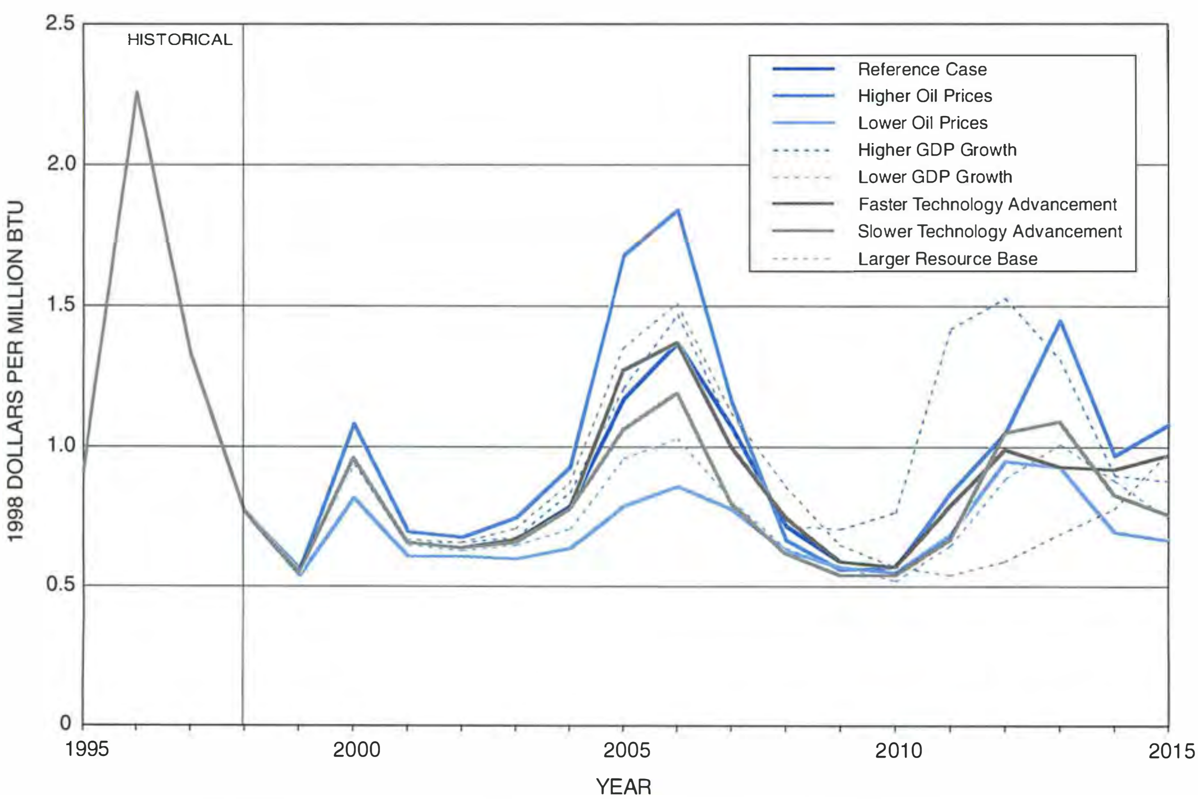


Figure T-21. Change in AECO Price versus Southern California

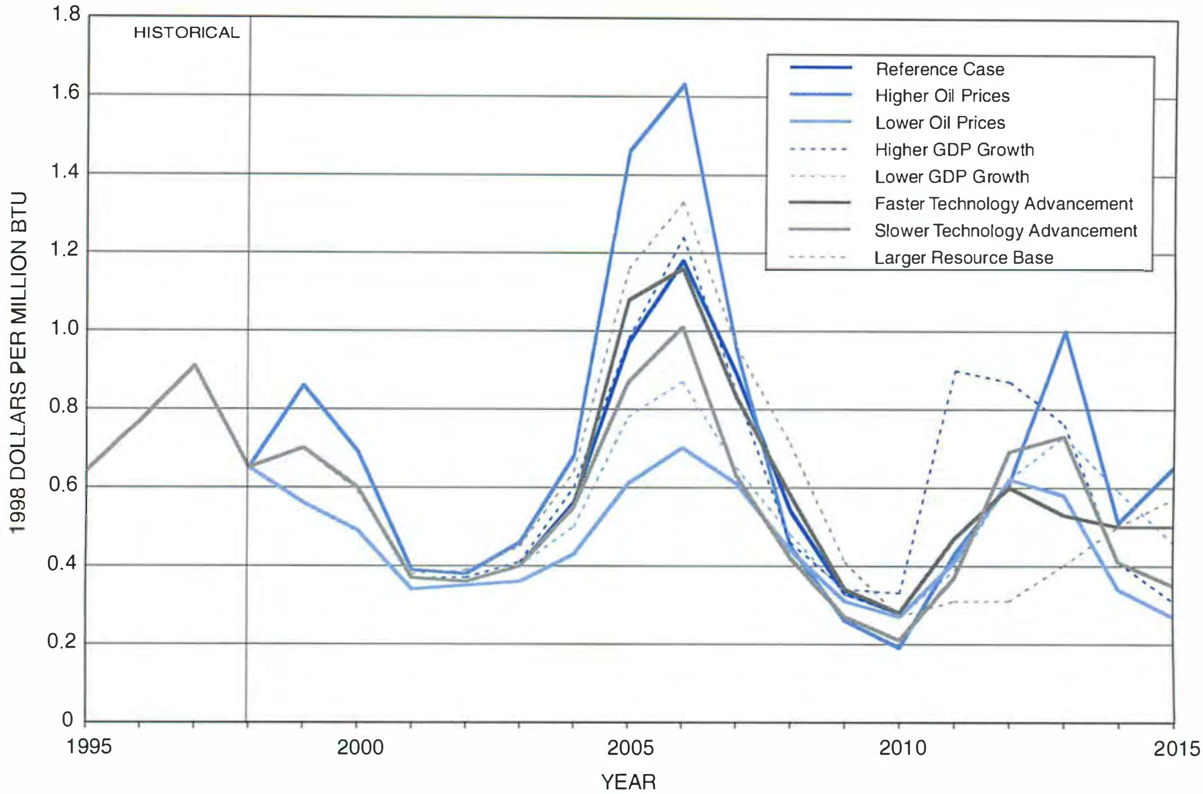
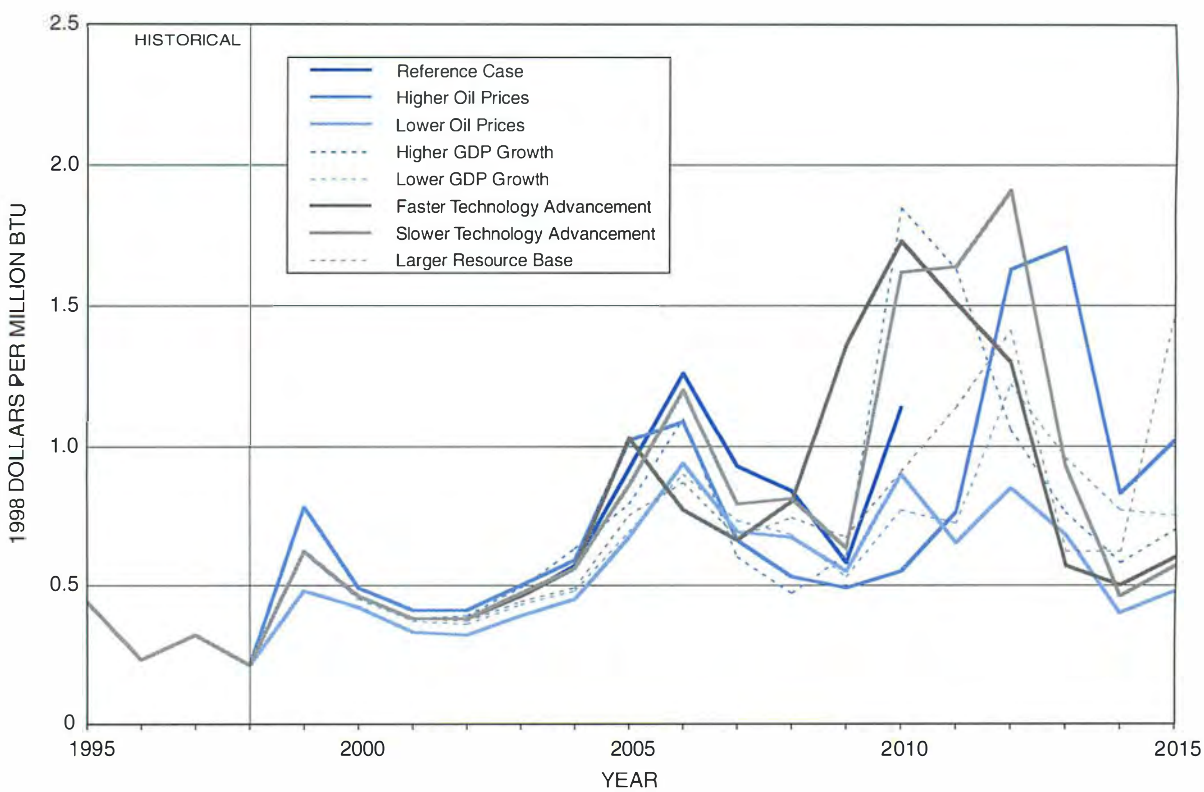


Figure T-22. Change in Opal Price versus Southern California



Two conclusions can be drawn from these trends in basis. Prices are increasing faster at Henry Hub than at AECO, and prices at AECO are increasing faster than at Opal. This reinforces the conclusion that the pattern of pipeline expansion for the Reference Case and all sensitivities is driven by declining production post-2010 for the Gulf Coast shelf and Western Canadian Sedimentary Basin, as shown in the Supply Task Group Report.

As discussed earlier, gas prices grow throughout this projection. Average acquisition prices for gas delivered to transmission pipelines increase significantly throughout this forecast, mirroring the significant increases in production area prices. In real terms, transmission revenue declines nearly 14% by 2010 in the Reference Case. Transmission revenues decline over the projection in the Reference Case and all the sensitivities as can be seen in Figure T-23. Two factors drive this decline. The first is the assumption that shippers become less willing to pay contractual premiums (revenue in excess of the marginal value). The second is the assumption that operational efficiencies decrease the unit costs of transmission over time. As shown in Figure T-24, the decline in unit revenues is more than offset by increased pipeline throughput, hence total pipeline revenues increase over time even though unit revenues are declining.

In real terms, per-unit distribution revenue also declines over time, as can be seen in Figure T-25. This is largely due to competitive pressures resulting in improvements in operational efficiencies over time, as well as growth in high-volume power generation load. As with transmission, increasing gas volumes more than offset the decline in unit costs, yielding a small increase in real revenue for distributors, as shown in Figure T-26.

Fuel costs, the costs of fuel used in the compression of the gas to move it to markets, go up steadily in the Reference Case and all sensitivities, as seen in Figure T-27. As one would expect, fuel costs increase from the increased load factor and the larger market being served. They also increase due to higher wellhead prices.

As mentioned previously, average annual requirements are projected to increase beyond 31 TCF by 2015, which equates to 87 BCF/D. Peak-day requirements will grow from approximately 111 BCF/D in 1997 to over 152 BCF/D in 2015, as shown in Figure T-28. Seasonal requirements are projected to grow as well. However, the annual load profile by month will become flatter.

The winter peak demand month in North America generally occurs in January while summer peak demand month usually occurs in August. The average North American daily demand in January divided by the average daily demand in August gives a seasonal demand ratio. The larger the ratio, the greater the difference between average winter and summer peak months. As can be seen in Figure T-29, the peak month seasonal demand ratio for the Reference Case and all sensitivities trends downward. This shows that demand is becoming less seasonal. This is caused by the incremental load coming from power generation, which peaks in the summer months.

Large seasonal price spreads justify significant investments in new gas storage. Over 0.4 TCF of additional working gas storage capacity is added in the Reference Case through 2010 and an additional 0.4 TCF by 2015. Cumulatively, this is equivalent to 21% of today's capacity. As can be seen in Figure T-30, most of the storage is built in the Mid-Atlantic region. Other areas that see significant amounts of additional storage are the Pacific Northwest, Mountain (Rockies), and California regions. The key driver for the amount of storage addition is the change in oil price. Higher oil prices cause fuel switching and increased demand for gas while lower oil prices cause fuel switching to oil and decreased demand for gas. This is the greatest factor in seasonal gas pricing differences. In the Higher Oil Price sensitivity, over 1.0 TCF of additional storage is built in the lower-48 states, as shown in Figure T-31. Most of this is built in the last few years of the forecast, as shown in Figure T-32. This occurs in all the sensitivities and is a result of significant wellhead gas price increases in the latter years of the analyses due to the constrained supply resource base. In the Lower Oil Price sensitivity, only 0.62 TCF is built.

Figure T-23. Transmission Unit Revenue

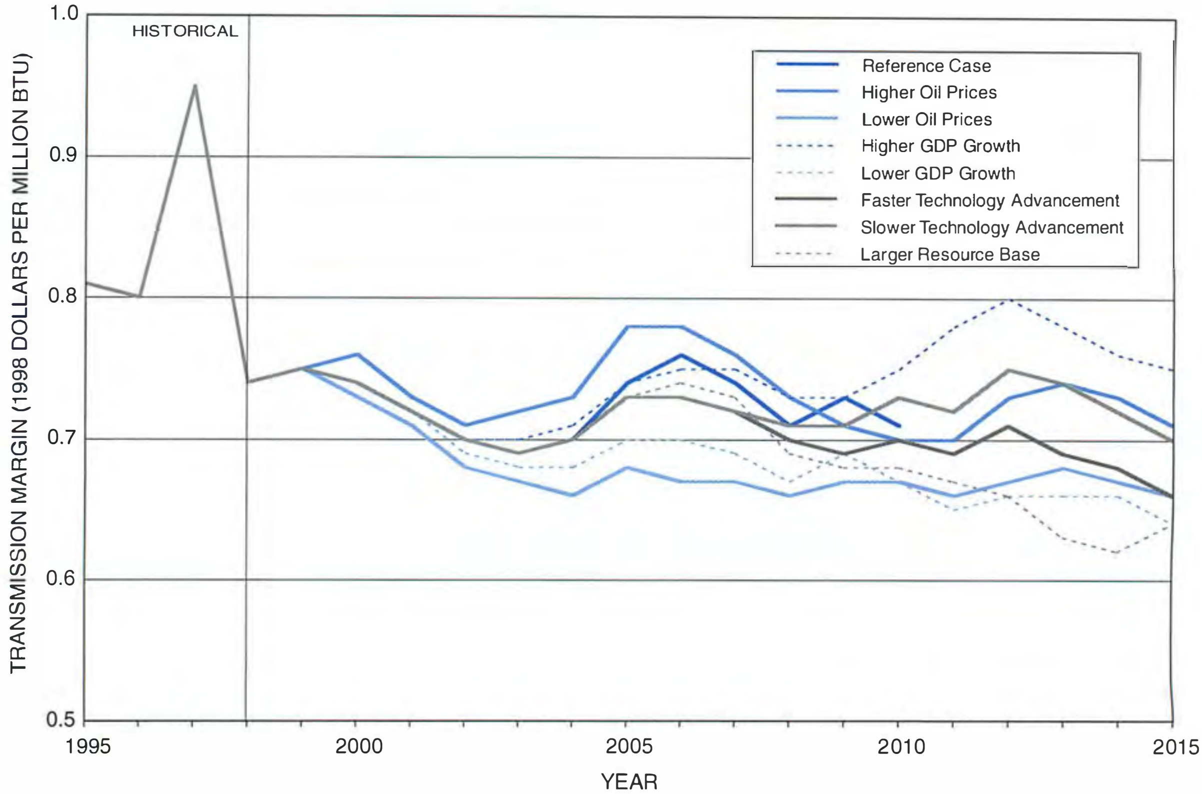


Figure T-24. Transmission Revenues

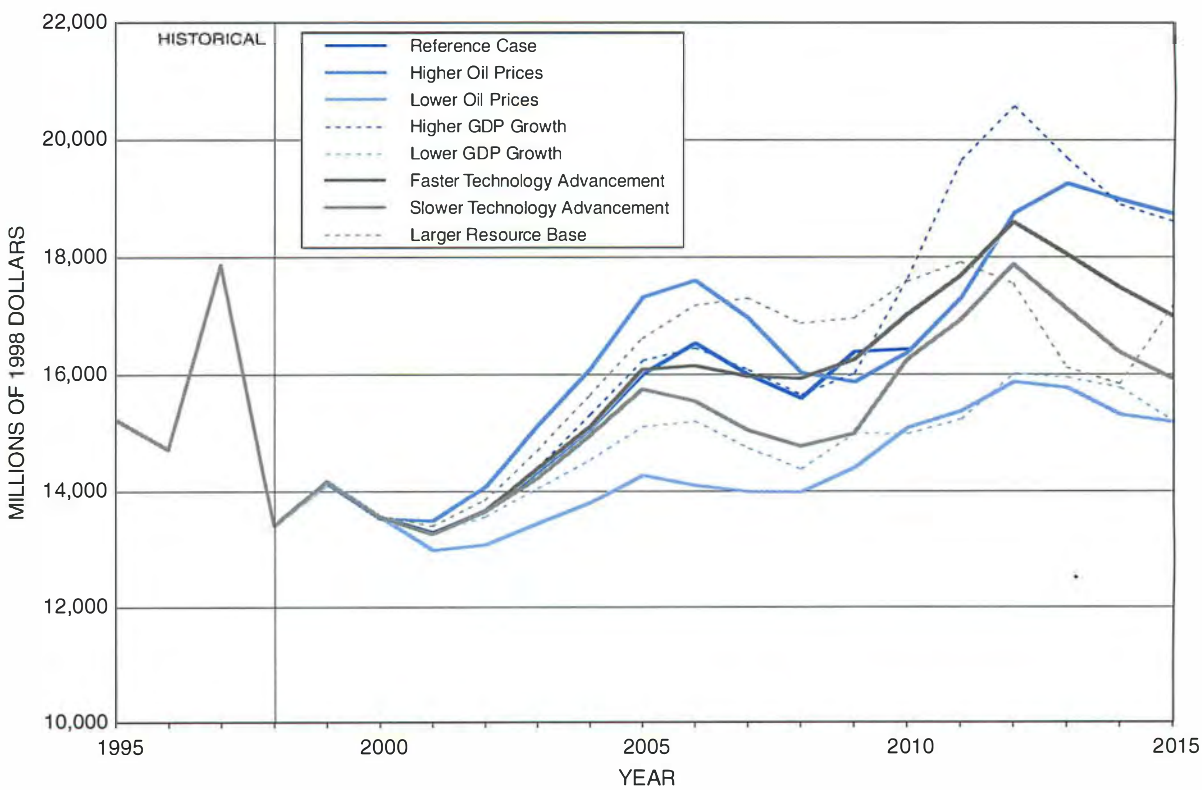


Figure T-25. Distribution Unit Revenue

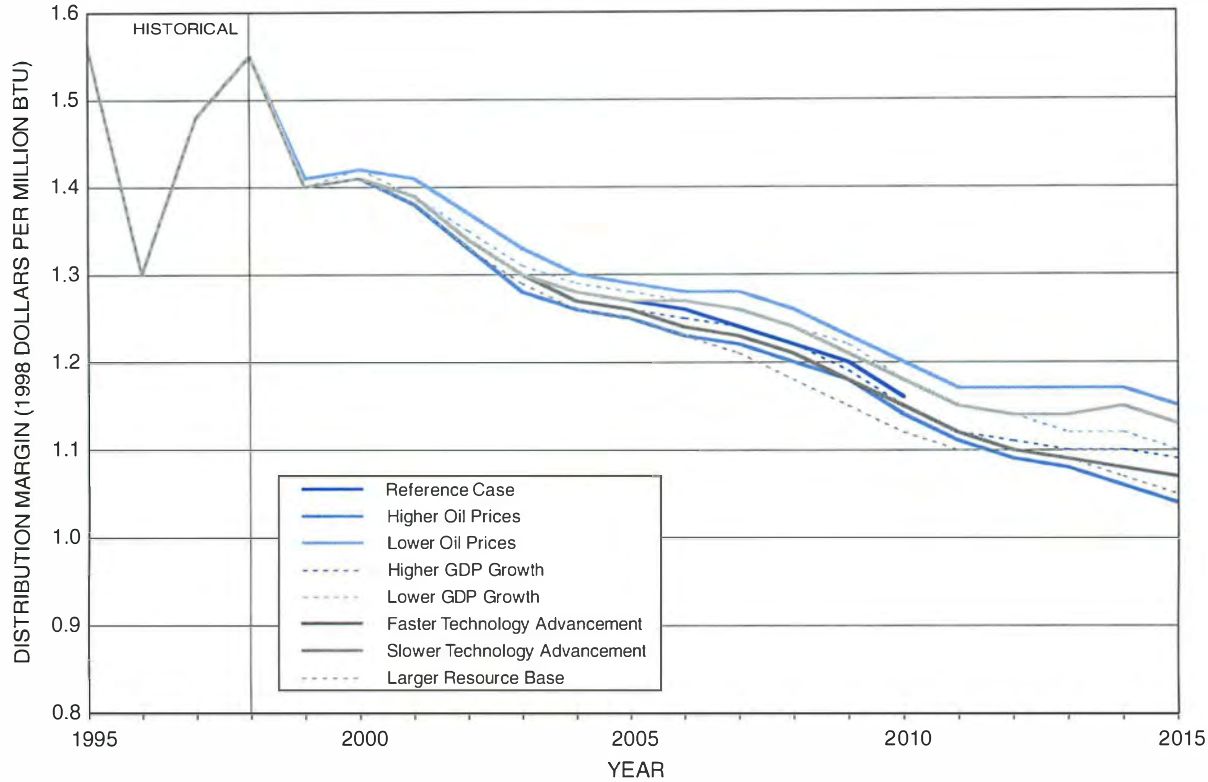


Figure T-26. Distribution Revenues

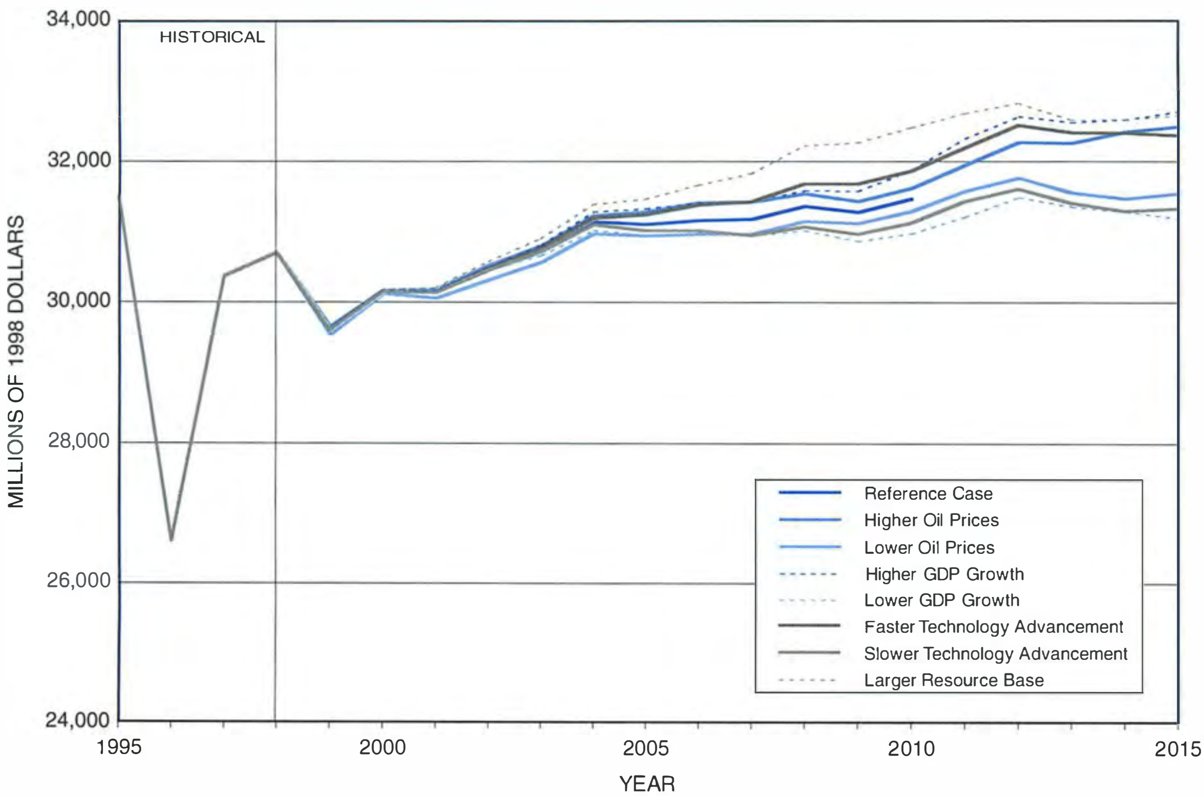


Figure T-27. Fuel Costs

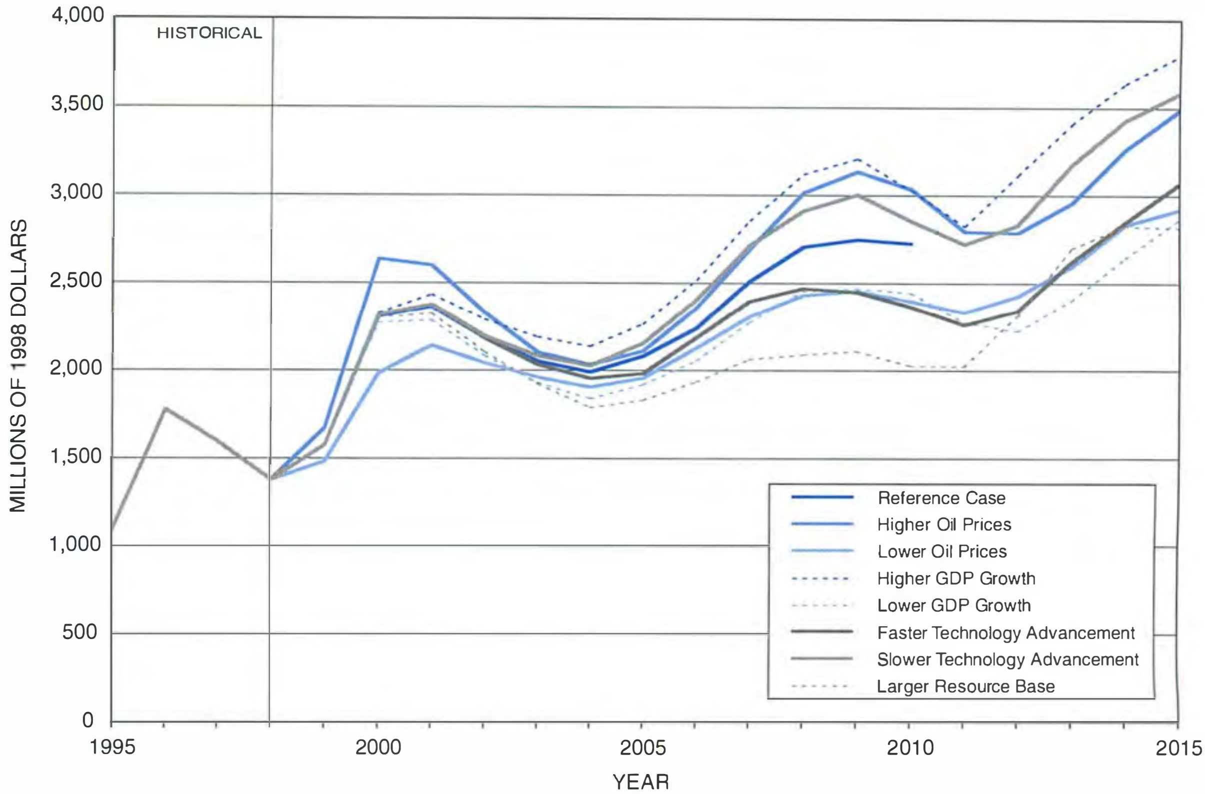
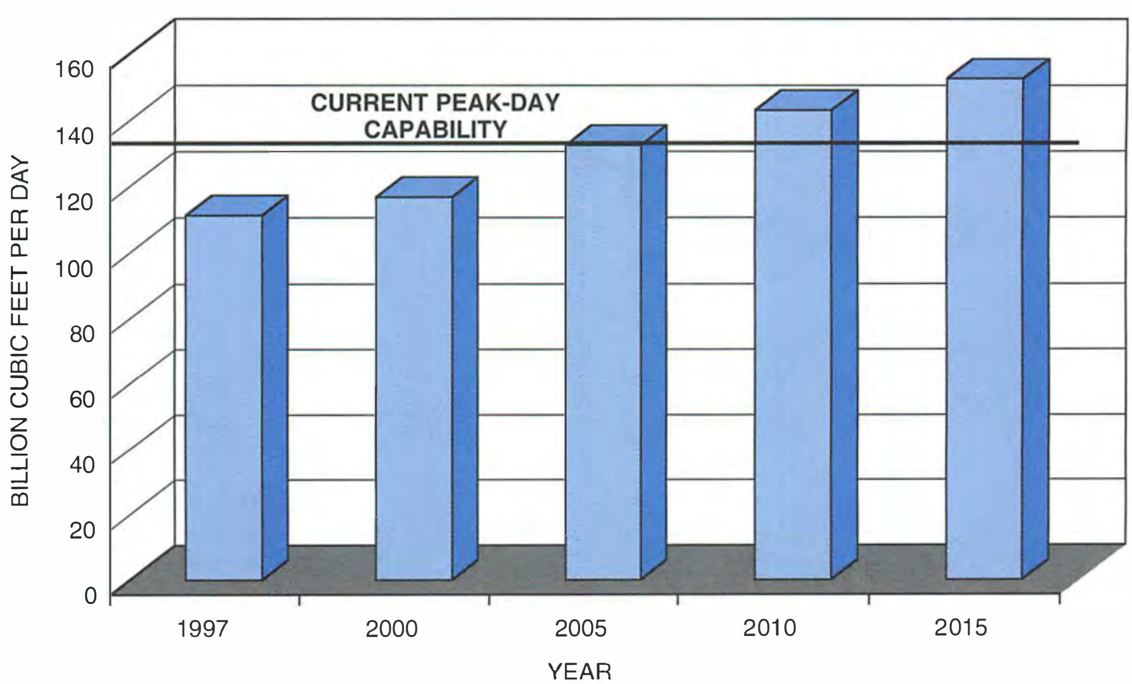


Figure T-28. Peak-Day Demand by Year



Source: EEA, Inc., Gas Market Data and Forecasting System.

Figure T-29. January/August Seasonal Demand Ratio

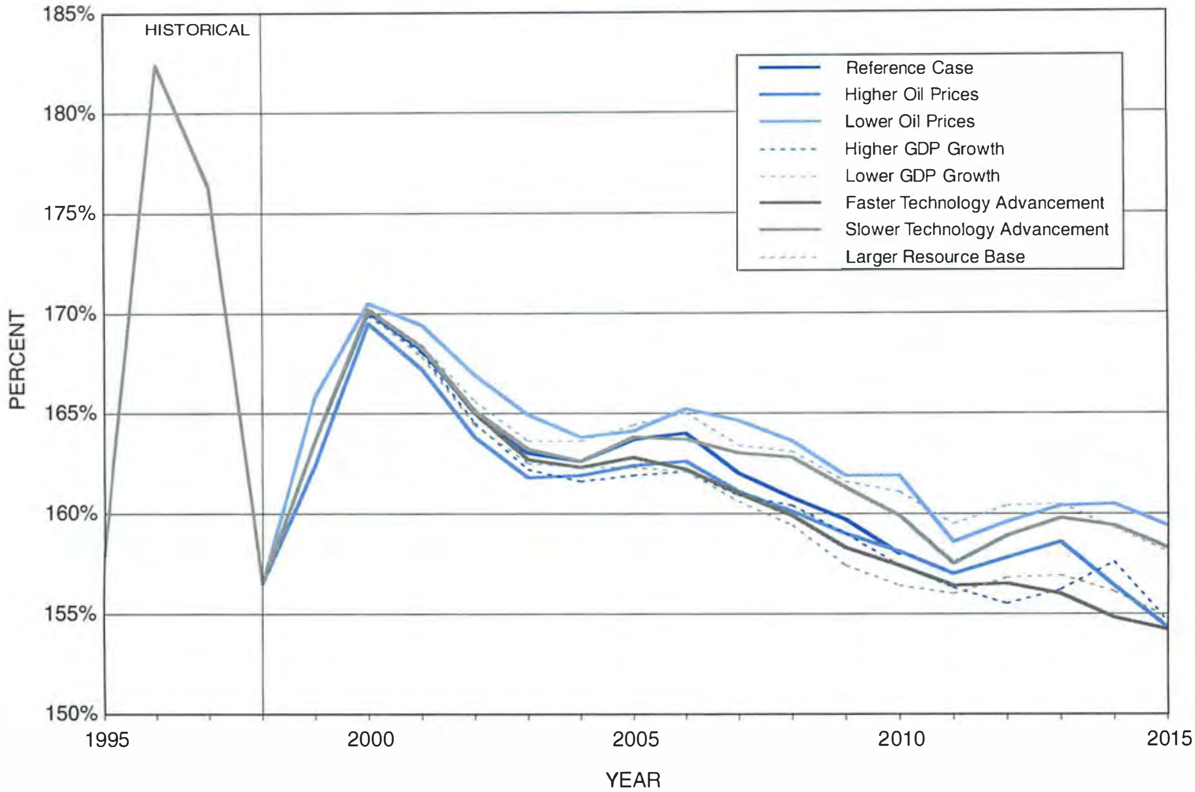


Figure T-30. Reference Case Cumulative Storage Capacity (Working Gas) Added to Market Areas through 2010

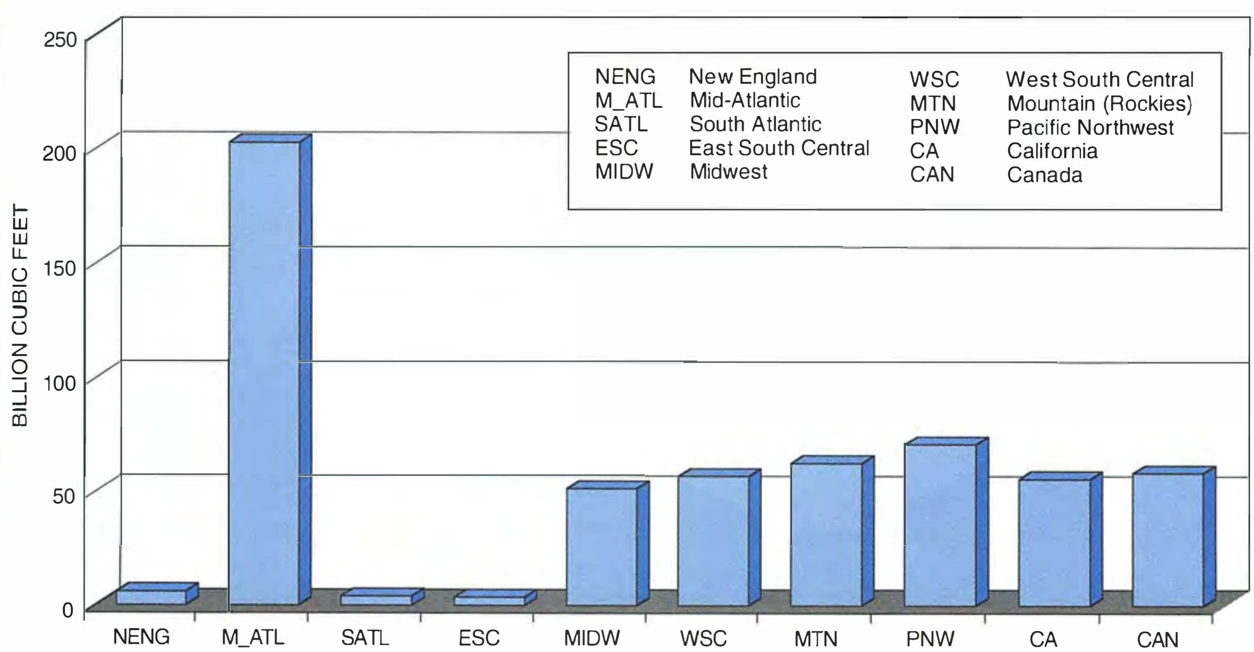


Figure T-31. Higher Oil Price Case Cumulative Storage Capacity (Working Gas) Added to Market Areas through 2015

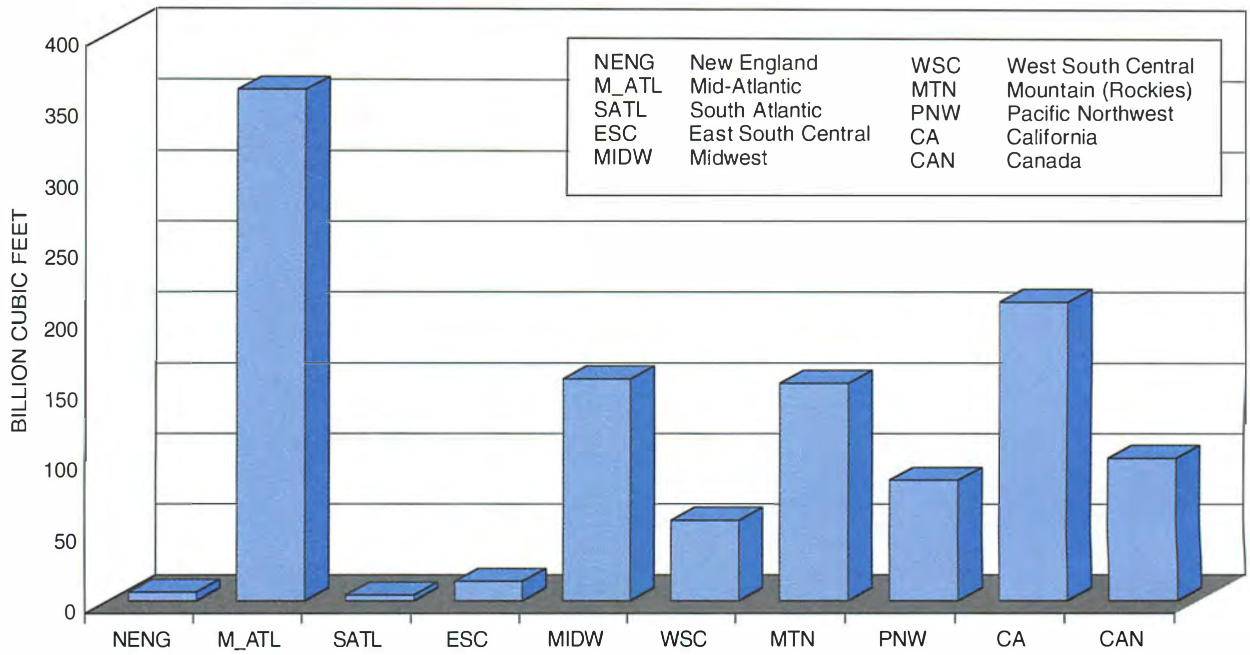
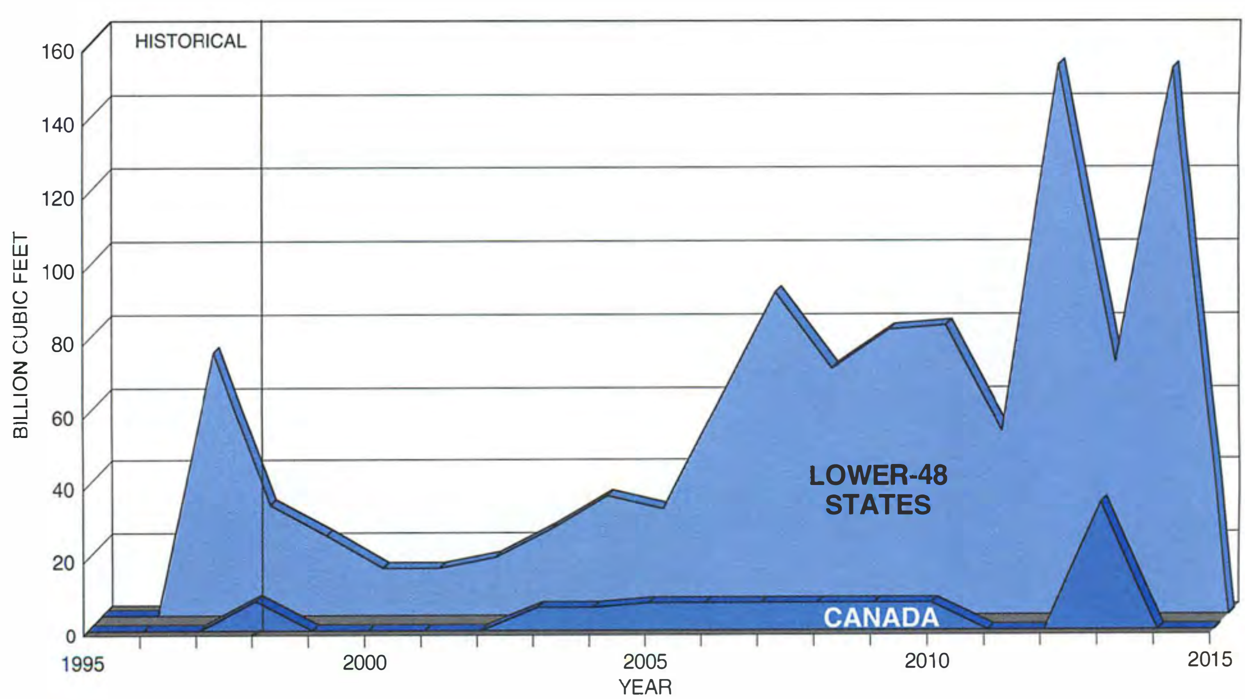


Figure T-32. Higher Oil Price Case Storage Capacity (Working Gas) Added to Lower-48 States and Canada



Conclusions

Significant expansion and enhancements to the delivery system will be required to serve the growing demand. Based on recent history, there is little concern that the projected increase will cause any significant problems.

Pipeline flows, basis, transmission margins, and revenues are significantly influenced by the regional supply shifts in all cases. In general, there are shifts in production to deepwater Gulf of Mexico, Rockies, western Canada, and the Canadian Atlantic. In the Reference Case, 71% of the new pipeline capacity built is from frontier supply areas. Canadian imports will continue to be a key factor in providing adequate supply to meet the growing demand of the lower-48 states.

New pipeline capacity in western Canada and the Rocky Mountains de-constrains gas supply in those regions. Declining supply in the Gulf Coast and Western Canadian Sedimentary Basin has significant influence on pipeline builds, particularly after 2010. This is somewhat mitigated in the Larger Resource Base sensitivity.

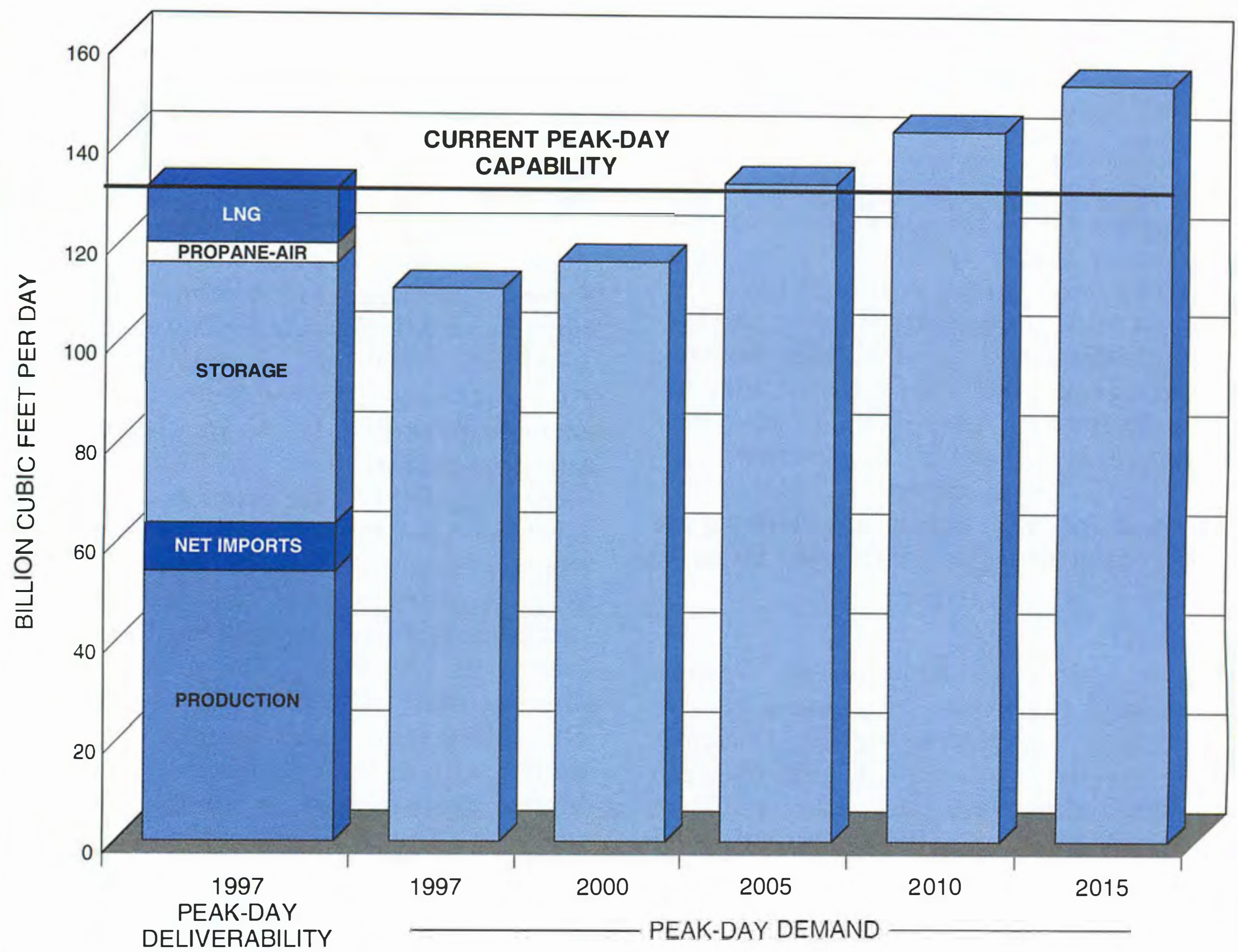
Natural Gas Storage and Peak-Day Demand

Peak-day requirements represent the sum of all loads on a system on the day of highest demand (as measured by volume). Gas utility systems use a combination of flowing gas, storage gas, and LNG or propane-air sources to meet their customers' firm requirements on peak days. Almost all U.S. gas pipelines and distribution companies experience their peak day during the winter months due to space-heating load that is highly dependent on weather and the severity of its conditions (primarily temperature and duration). During the remaining months of the year, these utilities have unutilized capacity beyond that needed to meet market requirements and to refill storage. It is this unutilized capacity and related unutilized system capabilities that is referred to elsewhere in this Transmission & Distribution Task Group Report as "seasonal or off-peak slack" in the delivery system.

Any particular system, whether a transmission pipeline or an LDC, must have the ability to meet its customers' firm requirements on design peak day. Therefore, the sizing and/or capabilities of these delivery systems are dependent upon the projected growth in peak-day requirements. The increased demand by 2015 in the residential and commercial sectors, and to a lesser extent the industrial and electricity generation sectors, will significantly increase peak-day demand and thus necessitate construction of additional pipeline, storage, and LNG or propane-air peaking facilities (see Figure T-33). Certain customers, principally industrials and electricity generators, are willing (and in some instances required) to limit natural gas consumption on peak days and switch to another fuel. The flexibility to switch to alternative fuels, such as oil and coal that do not burn as clean as natural gas, is often limited by restrictions in environmental regulations. This is becoming more common, particularly for the new electricity generation facilities, as fuel-switching capabilities are becoming more difficult to permit in some areas of the United States. Thus, the new electricity generation load will likely have a higher impact on peak-day requirements than in the past. However, some level of fuel-switching capability is necessary to handle overall energy needs on peak days and to lessen pipeline and storage expansion needs.

In 1997, the U.S. natural gas transmission and distribution system was capable of delivering up to about 131 BCF of natural gas on a peak day. Of this amount, about 42% (54 BCF) was available directly from lower-48 natural gas production. The remaining capacity was provided by imports, storage withdrawals, LNG, and propane-air peaking facilities. Figure T-33 illustrates the relative importance of the different components in providing this capacity. As shown in this figure, natural gas storage and peaking facilities provide about

Figure T-33. 1997 Peak-Day Natural Gas Deliverability and Demand



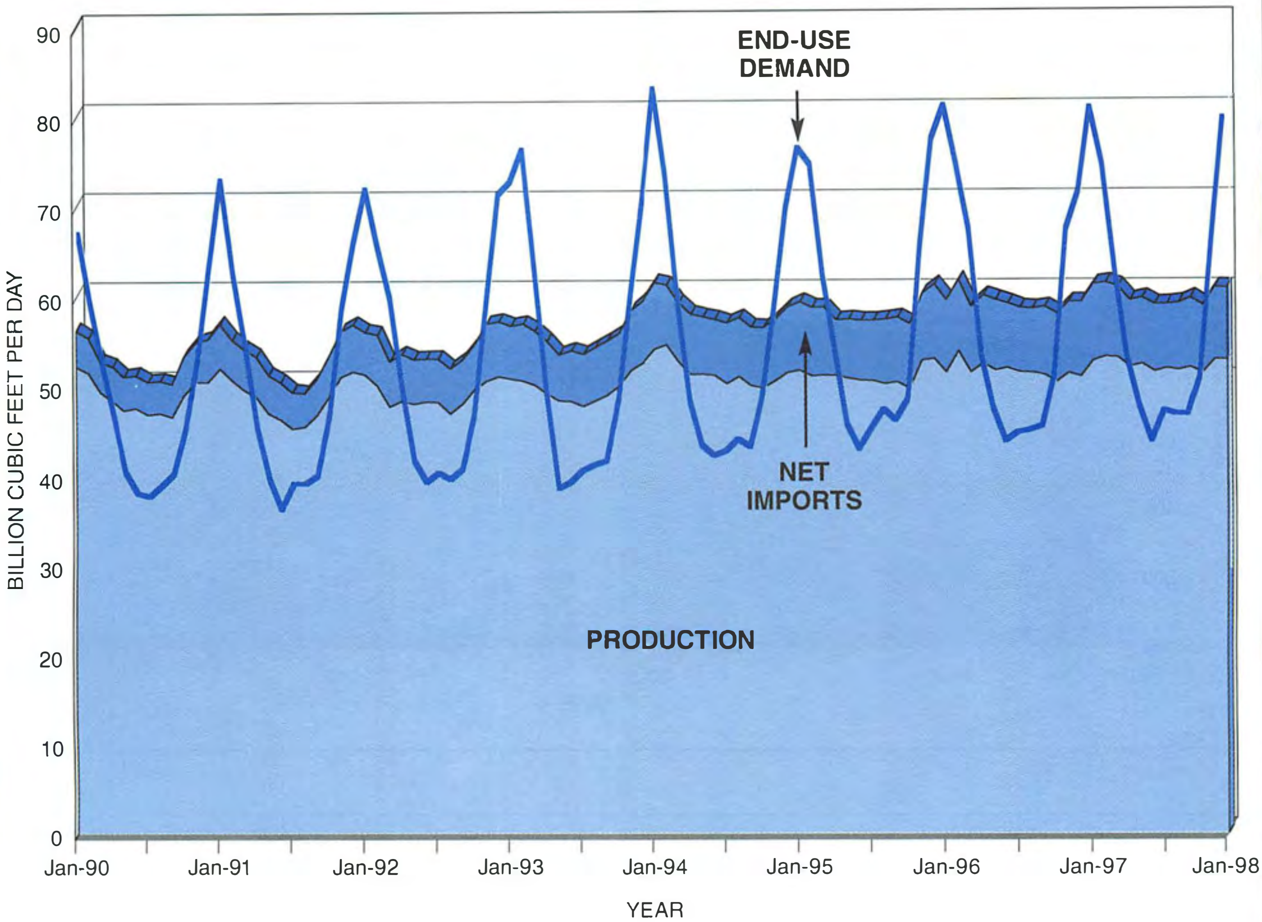
51% (67 BCF) of peak-day gas supply.[1] This additional capability above the 1997 annual consumption of 22 TCF, and estimated peak-day demand of 111 BCF/D, allows non-firm customers to use capacity on peak days, adds reliability, and enables the system to support a growing U.S. gas market over the near term.

Storage facilities also smooth over differences between natural gas production patterns and seasonal changes in natural gas demand, and minimize the total costs of the natural gas transmission and distribution system. Figure T-34 compares the seasonal pattern of U.S. natural gas demand with domestic production and Canadian imports.

The differences between supply (production and imports) and demand are accounted for by injections into and withdrawals from storage. Without storage, both production deliverability and delivery system capacity in the United States and Canada

[1] EIA estimates total lower-48 natural gas storage field deliverability to be about 75 BCF/D. This figure represents the sum of the non-coincidental peak-day deliverability reported by each individual field. Actual useful coincident peak-day deliverability is significantly lower. Many fields share infrastructure (such as pipeline capacity) that constrains useful deliverability on any given day to less than the sum of the maximum deliverability of the individual fields. In addition, many fields are sited in regions or locations where the full deliverability will not be required or useful on a national peak day. For example, in the producing areas, less than half of available storage working gas capacity is used, and peak-day deliverability for these fields will be commensurately lower. Finally, the deliverability reported by the EIA may not fully reflect field degradation over time. Actual effective storage peak-day deliverability for 1997 is estimated to be about 52 BCF/D.

Figure T-34. U.S. Natural Gas Supply and Demand



would need to be greatly increased to meet peak winter demand.

New Storage Requirements

Lower-48 end-use natural gas demand is projected to increase by 32% from 19.9 TCF in 1997 to 26.3 TCF by 2015 in the Reference Case. A significant amount of new storage capacity and storage deliverability must be developed to meet this increase in demand. As shown in Figure T-35, lower-48 storage capacity for working gas is projected to increase by 21% between 1997 and 2015, from 3.8 TCF to 4.6 TCF. The increase in storage capacity is estimated to require a total investment of almost $5 billion (1998$). The annual investment costs associated with storage field expansion are shown in Figure T-36.

The need for new storage facilities in the future will be driven by two major factors. First, increases in seasonal natural gas demand and seasonal natural gas price spreads will stimulate demand for storage capacity. Second, operational changes in the nature of gas demand and transportation (including short-term fluctuations of demand in the power generation sector and the growth in importance of hub storage to meet operational requirements) will stimulate demand for high-deliverability storage fields such as salt dome storage and strategically located depleted field storage with greater operational flexibility.

The need for new storage capacity is driven primarily by the increase in seasonal natural gas demand (including peak-day demand) relative to the overall annual average natural gas demand. Figure T-37 shows natural gas demand load duration curves for 1997, 2000, 2005, 2010, and 2015 corresponding to the Reference Case. Each load duration curve represents daily lower-48 demand, determined using 1997 weather in each year,

Figure T-35. Lower-48 Storage Field Working Gas Capacity

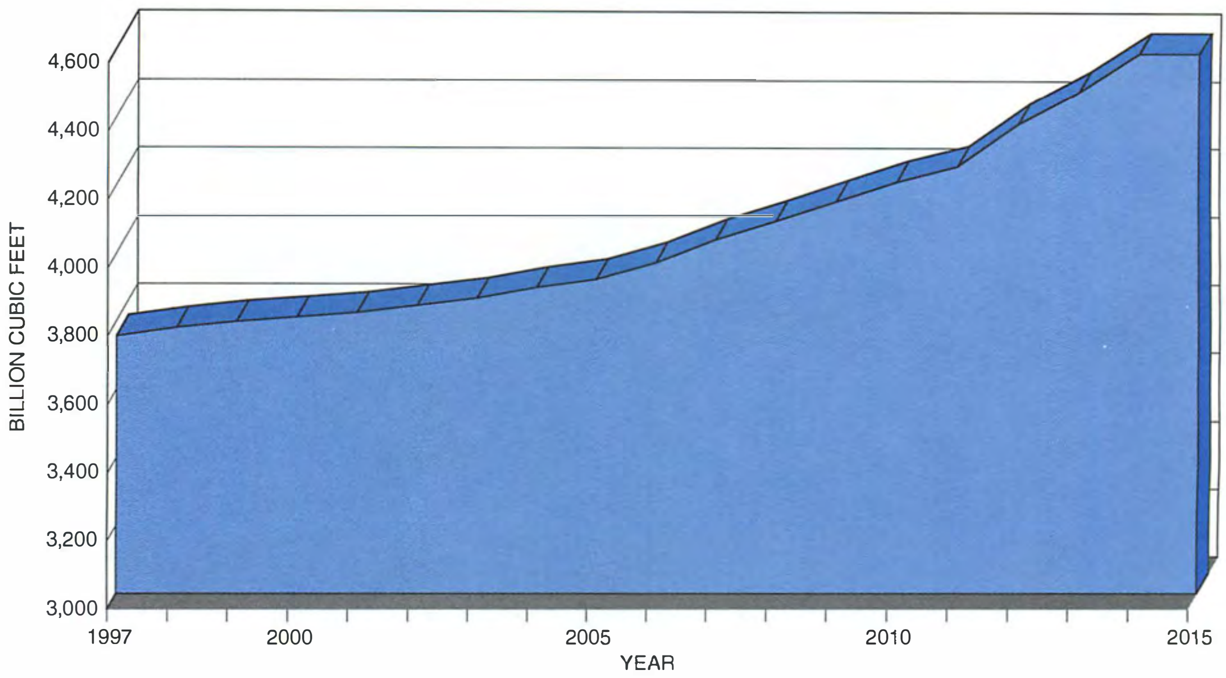


Figure T-36. U.S. Storage Expenditures

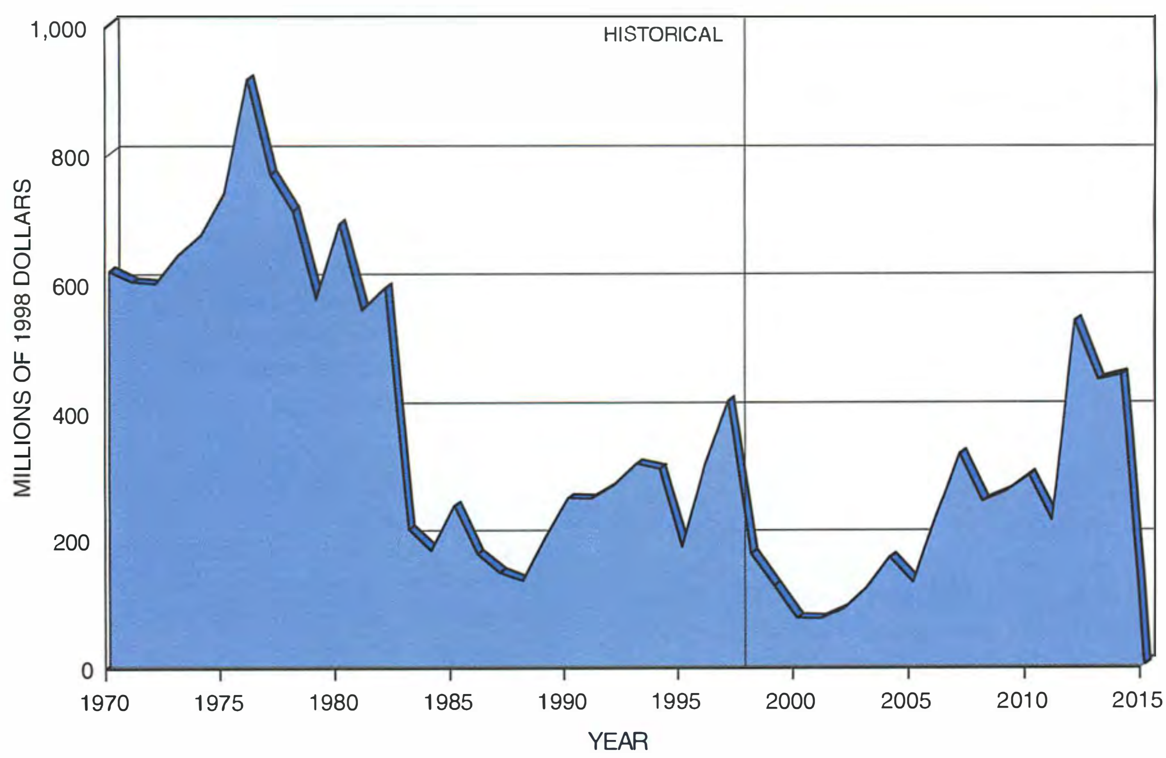
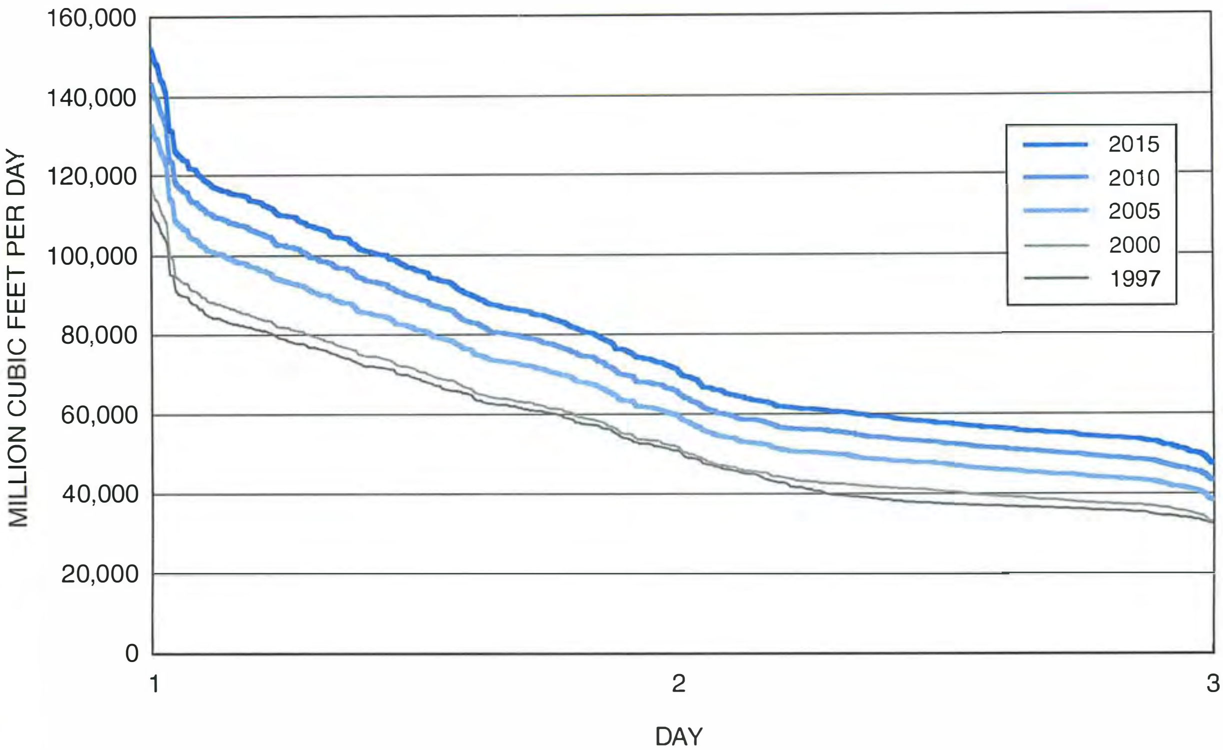


Figure T-37. Total Lower-48 End-Use Demand
Peak-Day Demand Analysis



sorted from the highest coincident peak day to the lowest. This figure illustrates the growth in coincident peak demand for the lower-48 states between 1997 and 2015.

Overall, the load duration curve for 2015 is slightly flatter than the load duration curve for 1997, reflecting the large growth in electricity generation demand relative to the other end-use sectors. The electricity generation demand for gas tends to peak in the summer and otherwise spread evenly throughout the remaining months of the year. Nonetheless, the gap between the peak-day demand and average demand continues to grow throughout the period, indicating that additional storage and peaking capacity will be required.

Table T-4 illustrates the increase in peak-day gas requirements for the Reference Case. Between 1997 and 2015, peak-day demand is expected to increase by 40.7 BCF/D, or 37%. Average daily demand increases by 23.4 BCF/D, indicating that peak-day demand is expected to increase by 17.3 BCF/D more than average daily demand. New transmission capacity upstream of storage will be required to meet the increase in annual average demand. New storage and peaking facilities, as well as transmission and distribution

TABLE T-4

CHANGES IN LOWER-48 PEAK-DAY DEMAND PATTERNS
(Reference Case)

	1997	2000	2005	2010	2015
Average Daily Demand (BCF/D)	54.5	56.6	65.3	71.9	77.9
Peak Day Demand (BCF/D)	111.1	116.6	132.4	143.0	151.8
Difference Between Peak Day and Average Day Demand (BCF/D)	56.6	60.0	67.1	71.1	73.9

pipeline capacity downstream of storage, will be required to meet the incremental growth in peak-day demand.

The type of facility selected to meet the incremental growth in peak-day demand will depend on the location (upstream or downstream of the city gate) and duration of the incremental peak load. While most of the increase in peak-day demand will be downstream of the city gate, there will be an increasing contribution to peak-day requirements upstream of the city gate due to baseload electricity generation units served off the transmission pipelines. Table T-5 indicates a significant amount of incremental growth in peak season demand in an addition to the peak-day demand growth shown above. This table compares average daily demand to the average daily demand during the highest usage quartile of the annual load profile, e.g., the average of the 91 days with the highest demand.

Overall, the growth in seasonal and peak-day demand indicates that seasonal natural gas deliverability will need to increase by roughly 31% between 1997 and 2015. Because most new pipeline construction is not economic unless operated at very high annual load factors, the bulk of the increases in seasonal and peak-day incremental demand will require construction of additional storage and peaking facilities.

Potential to Expand Storage Capacity

The Reference Case indicates that about 800 BCF of working gas capacity must be added to natural gas storage capability in order to meet the expected increase in seasonal and peak-day demand. This represents a 21% increase over the available working gas capacity in 1997. The U.S. Energy Information Administration (EIA) regularly tracks proposed storage field development and expansion projects. As of 1997, the EIA was tracking a total of 95 proposed storage projects with a total of 372.2 BCF of working gas capacity and 10.5 BCF/D of deliverability.

Data tracked by AGA showing storage field expansion potential of existing fields indicates the technical potential to expand existing fields by more than 2 TCF, with an estimated 1.2 TCF of working gas capacity. In addition, new storage fields not yet announced are also likely to be developed. Hence, the technical feasibility of expanding storage capacity to meet the Reference Case requirements would not appear to be a significant concern. However, the costs of storage expansion appear likely to increase over time as lower cost storage opportunities are developed first. For a more detailed discussion, see Appendix M.

The storage field expansion potential included in the AGA storage database is almost certainly higher than the level of expansion in existing fields that will be achieved over time. Roughly half of the potential is located in aquifer fields. Due to cost concerns, and the limited flexibility of these fields, much of this potential capacity is likely to remain undeveloped. In addition, a significant proportion of the expansion potential for depleted field storage facilities probably will never be developed due to a variety of problems, including costs, land use and per-

TABLE T-5

CHANGES IN LOWER-48 SEASONAL DEMAND PATTERNS
(Reference Case)

	1997	2000	2005	2010	2015
Average Daily Demand (BCF/D)	54.5	56.6	65.3	71.9	77.9
Average of Daily Demand for 91 Highest Days (BCF/D)	80.8	83.9	96.0	104.8	112.3
Difference Between Average Daily Demand for 91 Highest Days and Average Daily Demand (BCF/D)	26.3	27.3	30.7	32.9	34.4

mitting issues, poor field location, poor field geology, and other issues.

Conclusions

The evaluation of natural gas storage requirements indicates that natural gas storage will continue to play a key role in meeting seasonal natural gas requirements, and in ensuring the reliability and flexibility of the overall natural gas delivery system throughout the year. As natural gas demand increases throughout the forecast period, additional storage space and deliverability will also be required. The primary conclusions of the storage analysis include:

- Both peak-day and seasonal storage capacity will need to expand by roughly 25% between 1997 and 2015 in order to meet growth in seasonal and peak-day demand.
- Significant new investments in storage and peaking facilities will be required to meet future growth in seasonal natural gas demand. Overall, incremental storage investment during this time period is expected to total about $4 billion (1998$).
- There appears to be sufficient potential storage capacity available to meet projected storage requirements.
- The price of expanding storage capacity is likely to increase as the most desirable storage fields are developed or expanded first. The cost of storage expansions is closely related to the cost and effectiveness of new storage field wells, pipeline costs, and compression. Technological improvements in these areas, particularly in well productivity and drilling costs, will have a significant impact on future storage development costs and are likely to offset a significant part of the storage development cost increases.

Distribution Analysis

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. LDCs broadly categorize their sales and transportation service customers into two classes: firm and interruptible.

LDC 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. Distribution system capacity is adequate to meet firm loads, but may or may not be adequate to meet all interruptible gas customer load under design weather conditions.

It is projected that between 1999 and 2015, the gas industry will add about 900,000 new customers per year. Consequently, distribution companies will add about 15,000 miles of new mains per year, and approximately 10,000 miles of new service lines per year in order to serve new customers.

Distribution investment required to serve new customers can be classified into direct and indirect investments. Direct investments include the costs of new facilities needed to connect new customers to the existing system, and include mains extensions, installation of new service lines, and meters and regulators. Indirect investments include the costs of increasing system capabilities to serve additional customers, and could include mains reinforcements, regulator replacement, regional debottlenecking, and improved flow design. Indirect investment costs also include expansion of computer systems, new customer call centers, and other similar investments that improve customer service and reduce operating expenditures. LDCs typically install systems sized to allow for significant customer growth, hence the need for these types of indirect investments generally cannot be linked directly to a specific new customer or group of new customers.

Table T-6 shows distribution facility costs for new customers in 1997, used as the baseline for projecting future LDC investment requirements. These costs include the direct costs of connecting new customers, as well as an allocation for the indirect costs. The costs used in the NPC analysis are based on distribution system costs from a recent GRI study of LDC cost trends,[2] refined based on the

[2] GRI, *Historical Cost Trends and Current Regulatory Initiatives in the Local Gas Distribution Industry*, May 1999.

TABLE T-6

DISTRIBUTION FACILITY COSTS FOR NEW CUSTOMERS IN 1997

	Residential	Commercial	Industrial	Electric Utility
Distribution Mains ($/Foot)	$22	$22	$28	$30
Distribution Services ($/Foot)	$ 6	$ 6	$ 6	$ 6
Cost Per Meter	$250	$600	$1,500	$1,500

AGA "Best Practices" review. The allocation of indirect investment costs was calibrated to reflect total national LDC investment. It should be noted these reflect smaller average size industrial and electric utility connections. It is assumed the larger average size industrial and electric utility are connected directly to an interstate pipeline. Table T-7 shows the footage of Mains Per New Customer assumed. Other Facilities Per New Customer assumed in this analysis are shown in Table T-8.

TABLE T-7

ASSUMED FOOTAGE OF MAINS PER NEW CUSTOMER

Region	Residential Customers	Commercial Customers
New England	75	78
Middle Atlantic	65	70
South Atlantic	115	120
Florida	160	175
East South Central	115	140
Midwest	90	110
Upper Midwest	90	110
Central	85	110
South Central	110	120
Southwest	110	150
Mountain	85	110
West North Central	105	110
Northwest	105	110
California	50	60

TABLE T-8

OTHER FACILITIES PER NEW CUSTOMER

	Service Footage Per Customer	Meters Per Customer
Residential	60	1.00
Commercial	60	1.01
Industrial	200	1.70
Electric Utility	300	2.00

Distribution systems are in a state of constant maintenance and upgrade to ensure system reliability and to minimize future maintenance costs. Typically, mains and meters have an expected service life of about 40 years, resulting in a replacement rate of about 2.5% per year. Services generally have a much longer life, with a replacement rate of about 1% per year. Distribution Facility Replacement Requirements assumed are shown in Table T-9. Given current technology, it is generally much cheaper to replace facilities than to install new facilities. Most current mains replacements and upgrades can be completed by insertion of plastic piping into existing cast iron and steel pipe, which allows for higher pressures and increased throughput. System upgrades such as extended pipewrap accomplish the same results. The average replacement cost is expected to be about 50% of the cost for installing new facilities.

Between 50% to 60% of investment over the forecast period is attributable to new cus-

TABLE T-9

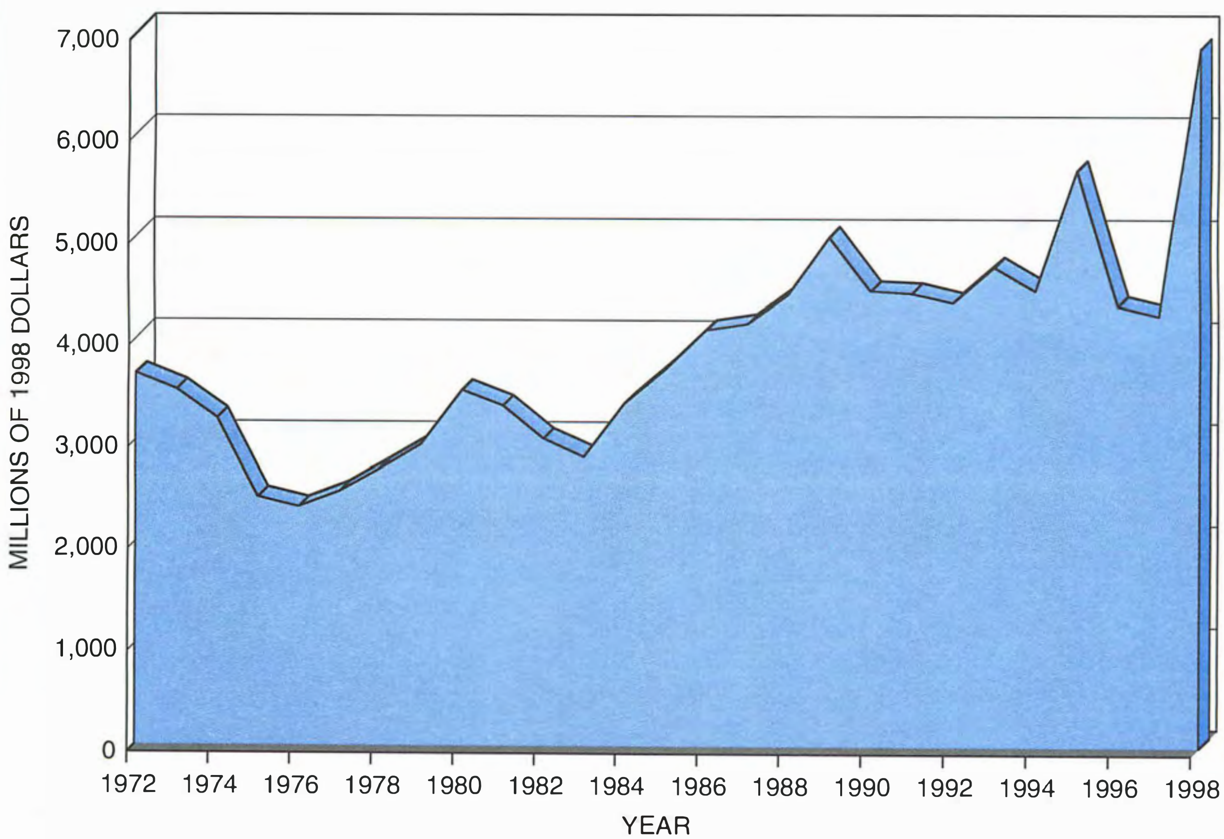
DISTRIBUTION FACILITY REPLACEMENT REQUIREMENTS

Facility Life	Years
Distribution Mains	40
Distribution Services	100
Meters/Regulators	40
Replacement Costs for Distribution Facilities	50% of new facility cost

tomer requirements, and 40% to 50% of investment for replacement and refurbishment of existing facilities. However, individual company requirements will vary substantially.

To accommodate the demand projected by this study, the results from the distribution analysis show that total annual facility investment requirements for distribution companies will average $4.9 billion. This is not expected to be a concern as average annual expenditures during the 1990s averaged slightly more than $4.8 billion. Historical annual capital expenditures in 1998 dollars can be seen in Figure T-38. It is assumed that distribution company productivity will increase by about 1.0% per year and this significantly lowers the projected costs. It is not expected that adequacy of the distribution infrastructure will be a constraint in the future. However, the permitting and construction of new or replacement facilities is becoming more expensive as a consequence of various growth management, building code, and environmental requirements.

Figure T-38. Historical Distribution Facility Investment



Chapter Two

Access: Rights-of-Way and Permitting

The projected shifts in supply regions and regional growth patterns will require building incremental pipelines to tap new supply sources, expanding infrastructure along existing corridors, building laterals to attach new markets, and attaching new storage facilities to the pipeline grid. A fundamental requirement to develop this infrastructure is access to land for attaching, gathering, and processing the natural gas and then transporting the natural gas to market or to storage fields for eventual delivery to market.

Just as access to land has become critical for the exploration and production segment of the industry, access will become more critical for the transmission and distribution segments. As discussed in detail in the Supply Task Group Report, access to public lands is necessary to better estimate the resource potential underlying these areas and eventually to develop the potentially economic gas resources. Access to rights-of-way or easements for pipelines to traverse public lands are not only needed to develop the resources underlying the public lands. It can also be needed when the most direct and cost-efficient route for a pipeline project to deliver supply from a non-public lands area to a market area would be to cross public lands. Having to route or reroute pipeline projects around public lands can increase the costs of projects, can result in an uneconomic project, and/or cause significant delays. Industry participants recognize on a case-by-case basis that there are valid reasons for restricting access to public lands. As some restrictions were put in place 20 or more years ago, aspects of these restrictions may no longer make sense due to new construction procedures, techniques, and improved land remediation methods. One example is improved directional drilling techniques for stream and river crossings. Another example is the modern compressor station, particularly if it uses electric motor drives, which is highly automated, relatively quiet, and has a much smaller footprint than compressor stations of the past. Access to public lands will become increasingly important to the growth of the energy infrastructure because much of the future supply will come from these areas.

Access issues are becoming increasingly important due to urban/suburban sprawl encroaching on existing rights-of-way, heightened public resistance to providing easements, and increasingly restrictive government policies and regulations. Urban/suburban sprawl has several impacts on the acquisition, management, and maintenance of easements and delivery system infrastructure. Surface structures and subsurface infrastructure (water, sewer, cable, etc.) resulting from urban sprawl create significant routing issues. Noise abatement and visual aesthetics can become issues as residential developments approach existing compressor stations or as compressor stations are potentially sited near residential areas and/or cultural landmarks. These issues have the potential to remove routes for new pipeline infrastructure not only for new supply to market area projects, but also for de-bottlenecking of existing infrastructure.

Also, the approaching of residential and commercial establishments near the rights-of-way/easements of high-pressure transmission pipeline and/or distribution pipeline may trigger a reduction in the maximum allowable operating pressure of the line segment by the Department of Transportation, thereby reducing pipeline efficiency. For transmission pipelines, this situation is easily remedied by either replacing the segment of pipe with thicker walled pipe or burying the replacement pipe deeper in the ground, depending upon the circumstances. For distribution systems, advancements in plastic pipe technology have resulted in the ability to operate distribution pipelines at higher pressures than currently allowed. This could be rectified, for example, through modifications to pipeline safety regulations that recognize technological advancements and current industry practices. A result of the ability to operate these types of pipes at higher pressures, if recognized by the Department of Transportation regulations, would enable more gas to move through the existing distribution systems. Hence, more flexibility in regulations would enable companies to utilize these advances in technology and practices without compromising safety, while increasing reliability and lowering costs.

Urban/suburban sprawl also impacts the maintenance of delivery system infrastructure by necessitating the use of different techniques and even the scheduling of maintenance so as not to disturb nearby residents. In addition, street opening permits and fees add costs to construction projects and tying in services after the mainline construction is complete requires additional fees and permits. These issues and the pressure they exert on increasing costs will be magnified over time with the growth in population and the need for delivery system infrastructure to support that growth.

Another consequence of a growing population and urban/suburban sprawl is increased public awareness and involvement in infrastructure projects. Although there are positive aspects of increased public awareness, greater public involvement can result in upward pressure on delivery system costs. A disturbing trend has arisen wherein the public has expressed resistance to the construction of new delivery system infrastructure, especially the large transmission pipeline projects such as those proposed from the Midwest to the Northeast and others in the Southeast. The resistance is often the result of misinformation, lack of information, and in some instances poor business practices. This has largely been the failure of industry and government.

Ultimately, government policies, regulations and their implementation at all levels of government (federal, state, local) guide and facilitate the ability of companies to obtain rights-of-way/easements and permits for the development of delivery system infrastructure. Major delivery system projects require extensive interactions with multiple levels and agencies of federal, state and local governments. For example, the recently constructed Portland Natural Gas Transmission System involved obtaining over 150 permits or approvals from federal, state, and municipal government agencies. There were 5 federal agencies, 23 state agencies, and 46 county and municipal agencies from which approvals were required. While some agencies look at different data, there is a tremendous amount of redundancy. More importantly, the large number of agencies increases the potential for inconsistencies in government policies and regulations and their interpretation.

Recently, both industry and government (specifically FERC) have taken action to address these types of public concerns to better enable the industry to meet the needs of both the market and of the public at large. For example, FERC recently amended its regulations (Docket No. RM98-17, Final Rule, Order No. 609) by adding certain early landowner notification requirements. FERC also issued the following orders to help facilitate pipeline projects:

- Collaborative Procedures for Pipeline Facilities Applications (RM98-16)—In this rule, FERC offers project applicants the option of designing a collaborative process to include environmental analysis and issue resolution prior to filing an application. FERC stressed that it will not prejudice processing of applications prepared by standard means nor curtail the legal rights of any party to intervene and participate fully in the Commission's post-filing proceedings. However, applicants may elect to treat the agreement as an offer of settlement if that is what the collaborative process yields. The Commission declined to adopt general deadlines, but participants can adopt deadlines for themselves in the process. Additionally, participants and not FERC are to determine the issues to be addressed in the collaboration. To initiate collaboration, applicants must file a request at FERC, which will be reviewed by the Director of the Office of Pipeline Regulation who will, after comments, decide whether to approve the proposed process. In conjunction with this rule, the Commission also issued a rule on early landowner notification requirements.

- Ex Parte Rule (RM98-1)—The Commission revised and clarified their ex parte rules this year in an effort to facilitate communications between staff and constructing pipeline personnel and between FERC and other agencies that share environmental jurisdiction.
- Order on Revising Existing Certificate Regulations (Order No. 603) (RM98-9)—FERC revised its certificate filing requirements and expanded the definition of "eligible facilities" under the blanket certificate prior notice procedures.

While many of FERC's actions are intended to streamline the certification process and facilitate communication among all participants, other access/permitting policies and regulations are becoming more restrictive and more complex in response to environment, landowner, and public-benefit concerns. The following examples of proposed or recently approved policy/regulatory changes demonstrate the movement toward additional requirements for the building pipelines:

- On July 21, 1999, the Corps of Engineers proposed to modify Nationwide Permits in certain areas, which if implemented could affect the ability to obtain permits in a timely and cost-effective manner.
- The U.S. Fish & Wildlife Service (FWS) has developed a "Draft Compatibility Policy Pursuant to the National Wildlife Refuge System Act of 1997" that would significantly impact the ability to obtain permits from the FWS for non-wildlife-dependent activities.
- On September 15, 1999, FERC issued a Statement of Policy (Docket No. PL99-3-000) that it will use in deciding whether to authorize the construction of major new pipeline facilities. The change in policy now requires that an applicant demonstrate that the economic benefits to the public outweigh the adverse impacts. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis and consider other interests. Prior to this policy change, the economic test was much simpler, relying on the percentage of long-term contracts as the measure of demand for a proposed project.

Careful consideration must be given to the issues enumerated in this and other sections of this study, in order to balance the myriad of interests and policy goals that exist. The consequences of conflicting policy and regulations within and across government agencies will lead to higher costs, directly or via delays, and hinder the ability of the natural gas industry to meet the energy demands of the nation.

Chapter Three

The Need for New Services to Serve Electricity Generation Loads

Restructuring

The ongoing regulatory restructuring of the natural gas and electricity markets and the dynamic operational requirements of serving the anticipated large load growth from electricity generators drives the need for new gas transmission, storage, and distribution services. The restructuring of the natural gas industry that began at the federal level in the 1980s has progressed through the 1990s and continues to unfold in many different ways and at differing paces at the state level. Restructuring is changing the roles, obligations, and interrelationships among all industry participants and creates both opportunities and risks for new market participants. As restructuring progresses at the state level, the traditional roles and obligations of LDCs will be changing. The provision of open access and unbundled services to all end-use customers may reduce the LDCs' obligation to serve with the corresponding and offsetting need for a new gas supplier to contract for firm transmission and/or natural gas supply. New gas-market participants may be obliged to accept some aspects of the former roles and obligations of the LDCs as services are unbundled and open-access customer choice is implemented. Many new participants, such as producers, generators, marketers, energy service providers, and end-users, have already begun to contract for and use transmission and storage capacity differently from the manner in which LDCs have historically obtained and utilized it. This is because their risks and market demographics differ from the load profiles and physical needs of the LDCs.

Natural gas restructuring led in part to the initiation of restructuring of the electricity industry. Traditional electric utilities are now reorganizing and unbundling their assets to become transmission and/or distribution focused and as such are either selling off or spinning down their generation assets to other commercial, non-utility entities. Many of the traditional regional electric pools have implemented, or will implement, regional commercial and operational transmission structures (RTOs) and rules that will allow electricity trading transactions to occur efficiently and transparently, both within new expanded service areas and between RTOs. A financial market for "forward power" is also developing alongside the physical market. This will introduce additional trading dynamics and settlement products or processes to the electricity trading business. A NYMEX electricity futures contract has been developed and trading hubs have been established within the Pennsylvania, New Jersey, and Maryland control area, at Palo Verde, and at the California-Oregon Border. Additional, non-NYMEX, trading hubs are likely to develop with time. In some respects, such as open-access transmission, the unbundling of services, and implementation of new market structures (futures and trading hubs), the electric restructuring is analogous to the natural gas restructuring. Likewise, the roles, obligations and interrelationships of the market participants are continuing to change as restructuring progresses and competitive market forces come into play.

A significant aspect of the electric restructuring on the natural gas delivery system and its services is the change in existing and new gas-fired generation asset management brought about by a more competitive electricity trading environment. The new owners/managers of generating assets face a market that is becoming more competitive and that may be more geographically diverse in terms of potential customers (markets) than that of the former electric utility. The new asset managers will be pursuing the maximization of margin as opposed to the minimization of production costs. This is particularly true for the managers of merchant plants (non-utility entities that bid their generation into the open market rather than dedicate such to a term-contract arrangement). Generation asset managers will be subject to day-ahead pool bidding structures that will influence bid behavior, the electric services bid, which entity will provide the product, the generation resource utilized, etc. It now appears the exact format of the pool bidding structures will vary by pool. Their ability to respond to different markets will require new flexible services from fuel-service providers.

Operating Character of Electricity Generation Load

While restructuring complicates and provides additional impetus for new flexible services, the basic drivers for determining the optimal configuration of new services targeted to serve electricity generators are related to the operational requirements of the load and the magnitude of growth in gas-fired generation. In years past, natural gas has been used in primary and co-firing applications in boilers to generate steam to push turbines. It has been used as the primary and/or alternative fuel source for early design gas turbines, operating either in simple or combined-cycle configurations. These early generation plants (units) have relatively low inlet pressure requirements and modest hourly flow rates. Some of these units are capable of operating on local distribution system facilities (mains). LDC no-notice service on the pipeline was historically sufficient to allow the LDC to support plant volume swings. Power load may have been interrupted, or the units requested to switch to alternative fuel if service to the plant conflicted with the LDC operations or needs. Others of these units are directly connected to interstate pipelines. These units generally utilized interruptible gas transportation services on the pipeline, and plant volume swings were often supported by linepack of the pipeline infrastructure. Also in the past, most load growth by the electric utilities was anticipated to be met by electric peaking unit applications, which in many cases was of minimal concern to the gas delivery system because it was for summer electric peak load occurring in the off-peak summer gas load season. To date, the "seasonal slack or off-peak slack" in the delivery system has been adequate to provide the capacity and operational flexibility needed to meet many of the demands placed on this system by increasing electricity generation load requirements while servicing the needs of the other gas customer segments.

For the foreseeable future, a new generation of high-technology, high-efficiency gas turbines lead the marketplace as the choice for electric power generation. These units—ranging in size from 40 megawatts to 200 megawatts each—have relatively high minimum inlet pressure requirements ranging between 475 and 680 psig, faster ramp rates to full load, and higher fuel quality requirements as compared to previous units. These units are likely to be served directly off the transmission pipelines.

In addition to meeting these equipment requirements, delivery system capabilities and services will have to respond to the growing dynamic electricity load patterns (as well as the load dynamics/requirements of the other gas segments/customers). Electricity load patterns vary regionally by season, by day of the week (weekday/weekend), and by hour of the day (peak/off-peak). Because electricity today cannot be efficiently and economically stored on a large scale, the electricity generation systems must be constantly monitored by the pool operator and adjusted to change their output instantaneously as electricity demand changes.

As gas-fired generation units are ramped up or down, and are brought on-line or taken off-line to follow electricity load, gas supply and the delivery systems will have to respond quickly (very quickly in the case of peaking units). This will require the ability to coordinate the nomination and scheduling of fuel supply and delivery services on an hourly basis. In order to accomplish this, differences in the "gas day" and the "electric day" must be reconciled and become more operationally transparent. The electricity generation operator will need to provide an estimated burn/dispatch profile to the delivery system operator to prepare their system for the anticipated demand. In addition, actual hourly operating/usage and next hour forecast data will need to be continuously exchanged between the operating entities in order to adjust their systems to real-time conditions that can vary considerably from estimates due unplanned plant outages and sudden variations in electricity load. An example of a transmission service that recognizes the need for hourly nominations and service capability is the recently approved FERC tariff filing by Reliant Energy for hourly firm pipeline transportation service.

Looking ahead, the tremendous growth in demand, particularly by electricity generators, will require the delivery system to be expanded, enhanced, and re-optimized to meet larger off-peak swing gas loads as well as growing gas annual and peak-day requirements. The expected annual growth of combined-cycle gas generation facilities in this projection (as well as those noted in forecasts of others) is in addition to previously anticipated summer season peaking units. The combination will increase annual and peak-day consumption. The increase in overall demand from all end-use sectors will soon begin to absorb/utilize much of the existing "seasonal or off-peak slack" in the current delivery system. As natural gas demand from electricity generation is projected to grow faster than all other sectors, there will also be an increasing amplification of the electricity generation load patterns and swings on the natural gas delivery system. To realize the growth potential from electricity generators will require infrastructure enhancements and expansions of the natural gas delivery system designed to meet the electricity market's requirements. Additional compression, optimally placed, that is more responsive to meet increasing short-duration load swings will be needed to bring the gas from supply areas to market hubs or city gates. This is especially true because most regional pipeline storage facilities are usually too far away from the specific pipeline segment affected and cannot change from injection to withdrawal mode quickly enough to match the remote electricity demand. New or enhanced communication and operations systems and software will be needed to coordinate and synchronize operations between the two industries.

Chapter Four

Uncertainty, Risk, and Attracting Capital for New Infrastructure

Although the capital required for transmission and distribution infrastructure expansions is not of the same magnitude as for the upstream sectors, investment issues are just as critical. The Reference Case shows that transmission and distribution companies will need to make capital investments of approximately $123 billion through 2015. This total includes $35 billion for transmission facilities, $84 billion for distribution facilities, and $4 billion for storage facilities. Clearly, to meet the needs of a 31 TCF market by 2015, companies will need to make considerable investments in infrastructure to serve new customers, manage seasonal and peak-day consumption swings, and replace aging facilities.

A primary question that looms in the transmission and distribution segments of the industry is about who will accept the changing risks of financing and constructing major new facilities to meet such a market. The changing risks stem from the restructuring of the natural gas and electricity markets, regulatory uncertainty, challenges in obtaining rights-of-way, and competition for capital.

The restructuring of the natural gas market started in the mid-1980s and has progressed through the 1990s. While the major aspects of restructuring at the federal level for interstate transmission have been implemented, there remains regulatory uncertainty in the process of "fine tuning" of the regulatory structure to meet the needs of the marketplace. In addition to uncertainty at the federal level, restructuring continues to unfold on a state-by-state basis for LDCs. There is considerable uncertainty for all industry participants as to the final "end-state" for LDCs. States continue to seek answers to questions such as who should be the provider of last resort and whether LDCs should be remain in the merchant functions. For example, many LDCs are in the process of either assessing, or reducing and divesting, their long-term interstate transmission contracts as state regulators redefine the LDCs' role in the marketplace. The new marketers that are taking over the merchant and service aggregator roles have risk profiles that make projects (greenfield or looping and compression on existing pipelines) harder to justify because of the short-term and competitive nature of the business. States' decisions on these and other issues will be driven by what is determined to be most beneficial for the local consumers. Regardless of its form, however, regulatory restructuring will continue to define and redefine the risk equation among the industry participants.

Over the last two decades, the industry restructuring has led to changing roles, obligations, and new market participants—as well as new risks and different risk profiles—for all the industry participants. In the past, cost recovery for downstream investments in gas pipelines and storage fields were heavily regulated and the process of aggregating demand for and support of investment in expansion of these facilities—as well as the process of facilities planning—involved primarily the pipeline companies and LDCs. The LDCs, as franchise holders, had principal access to the end-use market and thus had a level of certainty for entering long-term contracts that supported the investment in new facilities. Restructuring has led to the complication of these processes by increasing the number and diversity of participants and increasing competition. The larger number of market participants (and competition) makes it more difficult to aggregate demand because many of their customer portfolios are more geographically diverse than the "traditional" LDCs.

The increase in competition makes obtaining information/data/plans more difficult for facilities planning purposes as information once commonly or more readily available is now kept confidential due to competitive concerns. It also increases the potential for bypass of LDCs facilities to serve large industrial and electricity generator loads, thereby increasing the potential for revenue loss for the LDC and potentially increasing costs to other LDC customers.

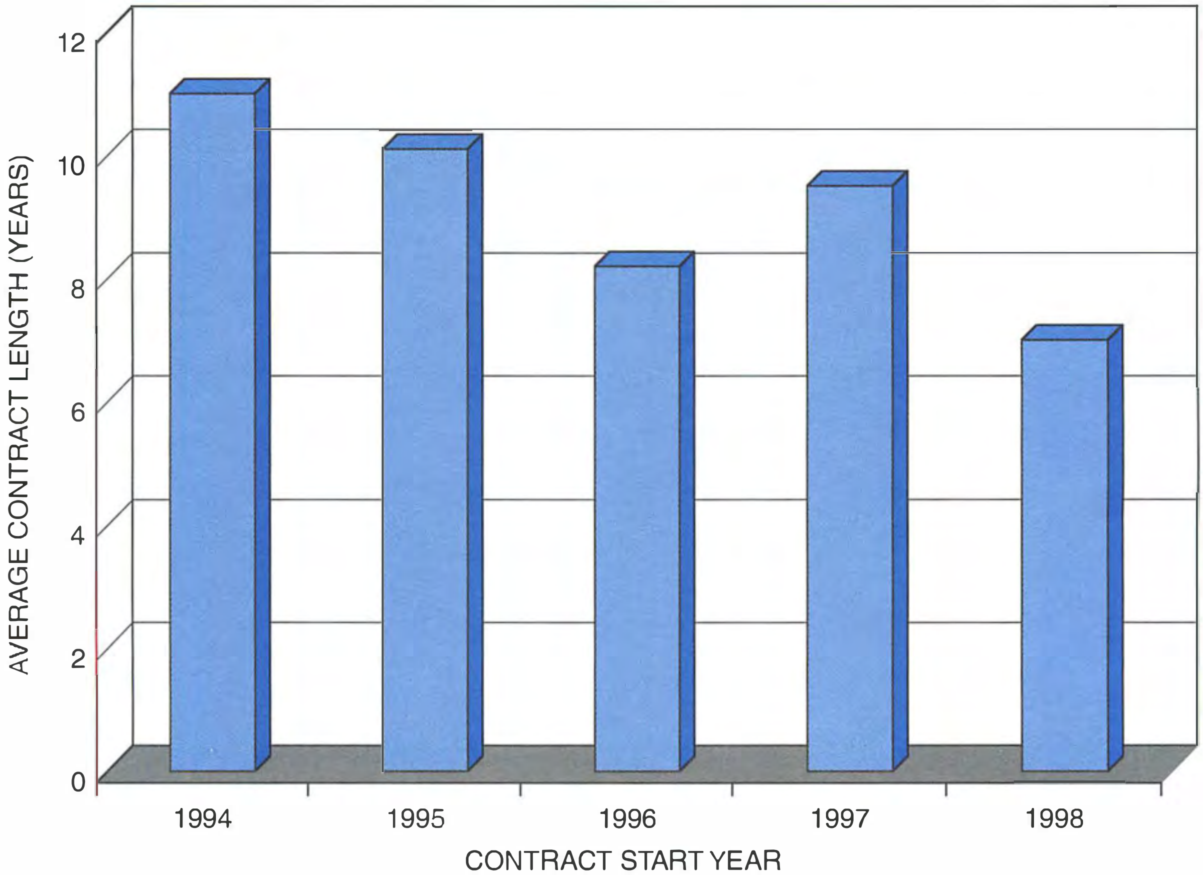
Much of the investment for transmission infrastructure is required to serve the enormous growth anticipated from the electricity generation sector. This market too is going through a major restructuring, creating uncertainty about the future economics of generating assets and fuel supplies. The restructuring will have electricity generators competing intensely with each other. Fuel supply, a major cost component for electricity generators, will be a major concern and plant owners/operators may be averse to entering into long-term wellhead and delivery service contracts that require any substantial guaranteed payments (demand charges) such as those needed for investment in new delivery system infrastructure. New supply to market area greenfield pipelines may be particularly susceptible to this problem.

As restructuring of the gas and electricity markets unleashes competitive market forces, the traditional forms of ratemaking for transmission pipelines and LDCs may not be adequate to meet the evolving needs of the marketplace. One alternative, however, is to allow for flexibility in pipeline rates while still protecting those shippers who may not have many options for service. One example of this type of solution is the move in federal regulation to allow pipelines to negotiate rates with shippers so long as a recourse or backstop cost-of-service rate is maintained. Most notably, this negotiating authority has been used by sponsors of new pipeline projects to design rates that enable the sponsors to clear the market hurdles for new projects. In this growth market, these and other types of creative and flexible regulatory policies will be necessary at the federal, state and local level. Other examples of creative solutions include incentive rate mechanisms that are developed by the company along with the regulatory agency that governs its rates.

In the face of changing market conditions, shippers place less value on entering contracts with a duration of more than three or five years. Shippers view a long-term obligation to pay demand charges as unnecessarily risky. In fact, the duration of long-term contracts has shown a significant decline since 1994, as shown in Figure T-39. As a result, there is a mismatch of risk between a pipeline's need for long-term contract commitments to minimize investment risk and the need of shippers to limit exposure to risk. This is true for the existing pipeline infrastructure, but there is an even greater mismatch problem for major new greenfield pipeline projects. To keep rates competitive, a new pipeline project requires substantial debt (usually 70-80%). This level of debt coupled with rate pressure requires debt terms of 15 to 20 years. LDCs who used to be able to sign 20-year contracts are generally not participants in new capacity projects because of state restructuring programs (discussed previously). The new market players generally have shorter time horizons with regard to transportation commitments, usually 3 to 5 years, and are thereby unwilling to sign long-term contracts for the capacity. This situation creates a mismatch between financing term and contract term that increases risk to the pipeline developer.

There are additional factors contributing to increased risks for delivery system infrastructure development and/or investment. A major factor that is more fully addressed in a separate section of this Transmission & Distribution Task Group Report is access to rights-of-way. The inability to obtain rights-of-way in a timely and

Figure T-39. Average Contract Length for Contracts with Terms of 3 Years or More, by Year of Contract Start, 1994 to 1998



Note: Data are for 64 interstate pipeline companies.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

cost-efficient manner increases the risk/uncertainty, particularly of major greenfield pipeline, that a project will be built. A long delay will make the return on investment lower than expected. This possibility could make the projects sponsors more risk averse as they pursue new projects or may make them pursue fewer projects.

The risks for the delivery system segments of the natural gas industry have changed substantially in this decade and will continue to change. From a fundamental financial investment perspective, risk requires a return on investment commensurate with that risk. If returns on delivery system investments are not commensurate with the risks inherent in the delivery system business, less capital will be invested in this infrastructure relative to investments in other businesses that have a better risk/return profile. To obtain the financing needed for the expansions and enhancements to serve a 31 TCF market, the energy companies that sponsor these projects must compete with other non-energy companies with similar risk profiles for the same capital.

Regulatory agencies that set the allowed rates of return need to be sensitive to the changing risks of this industry so that these companies are not disadvantaged in the capital markets and are able to raise the $34 billion for transmission facilities, $5 billion for storage facilities, and $84 billion for distribution facilities.

APPENDICES

Appendix A
Request Letters
and
Description of the
National Petroleum Council

Appendix B
Study Group Rosters

The Secretary of Energy
Washington, DC 20585

May 6, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

In 1992, the National Petroleum Council released a study entitled, "Potential of Natural Gas in the United States." That study was critical in identifying natural gas as an abundant domestic resource that can make a significantly larger contribution to both this Nation's energy supply and its environmental goals.

Since the release of the study, the Nation has experienced five years of sustained growth in the use of natural gas. In addition, the study did not anticipate at least two major forces that are beginning to take shape, which will profoundly affect energy choices in the future -- the restructuring of electricity markets and growing concerns about the potentially adverse consequences that using higher carbon-content fuels may have on global climate change and regional air quality. These issues offer opportunities and challenges for our Nation's natural gas supply and delivery system. For a secure energy future, Government and private sector decision makers need to be confident that industry has the capability to meet potentially significant increases in future natural gas demand.

Accordingly, I am requesting that the Council reassess its 1992 study taking into account the past five years' experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond. Of particular interest is the Council's advice on areas of Government policy and action that would enable natural gas to realize its potential contribution toward our shared economic, energy, and environmental goals.

Given the significance of this request, Deputy Secretary Elizabeth Moler will co-chair the study committee. I offer my gratitude to the Council for its efforts since our meeting in December 1997, to assist the Department in defining a more concise study scope. The breadth of issues related to natural gas supply and demand is vast and I recognize that further refinements in scope may be necessary once the study is underway to address the most significant concerns about future natural gas availability.

Sincerely,

Federico Peña

Federico Peña

The Secretary of Energy
Washington, DC 20585

November 18, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

This is to convey my approval to establish a Committee on Natural Gas and to appoint industry members as proposed in your letter of October 6, 1998. I also approve the establishment of a coordinating subcommittee and the appointment of subcommittee members identified in your letter.

The Deputy Secretary will serve as the Government co-chair of the committee; the Assistant Secretary for Fossil Energy will co-chair the coordinating subcommittee. Staff involved in this study will be from the Office of Fossil Energy and the Office of Policy and International Affairs. In addition, the Energy Information Administration has expressed an interest in providing technical and analytic support. The Deputy Assistant Secretary for Natural Gas and Petroleum Technology will serve as the alternate for the Government co-chair of the subcommittee.

I agree that it would be appropriate for a representative of the Department of the Interior to be a member of the coordinating subcommittee, and we are pursuing this issue.

For a secure energy future, Government and private sector decision-makers need to be confident that industry has the capability to meet the significant increases in natural gas demand forecasted for the twenty-first century. I am pleased that the National Petroleum Council recognizes the challenge facing the domestic natural gas industry and has agreed to conduct a study of natural gas supply availability. I look forward to the study's results.

Yours sincerely,

Bill Richardson

Bill Richardson

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 the Secretary, 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:

- *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)*
- *The Potential for Natural Gas in the United States (1992)*
- *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries (1993)*
- *The Oil Pollution Act of 1990—Issues and Solutions (1994)*
- *Marginal Wells (1994)*
- *Research, Development, and Demonstration Needs of the Oil and Gas Industry (1995)*
- *Future Issues—A View of U.S. Oil & Natural Gas to 2020 (1995)*
- *Issues for Interagency Consideration—A Supplement to the NPC's Report: Future Issues (1996)*
- *U.S. Petroleum Product Supply—Inventory Dynamics (1998).*

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 Chair and a Vice Chair, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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AECO	Alberta Energy Company
AGA	American Gas Association
API	American Petroleum Institute
BCF	billion cubic feet
BCF/D	billion cubic feet per day
BLM	Bureau of Land Management
BOE	barrels of oil equivalent
Btu	British thermal unit
CDD	cooling degree days
D&C	drilling and completion (costs)
DOE	Department of Energy
E&P	exploration and production
EEA	Energy and Environmental Analysis, Inc.
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERM	Enhanced Recovery Module of the Hydrocarbon Supply Model
EUR	Estimated Ultimate Recovery
FERC	Federal Energy Regulatory Commission
GDP	gross domestic product
GOM	Gulf of Mexico
GRI	Gas Research Institute
GW	gigawatts
HDD	heating degree days
HSM	Hydrocarbon Supply Model
IPP	independent power producer
KWH	kilowatt-hours
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MCF	thousand cubic feet
MMBtu	million British thermal units
MMCF	million cubic feet
MMS	Minerals Management Service
MW	megawatts

NERC	North American Electric Reliability Council
NOAA	National Oceanic and Atmospheric Administration
NPC	National Petroleum Council
NRC	Nuclear Regulatory Commission
NUG	non-utility generation
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
PGC	Potential Gas Committee of the Colorado School of Mines
R&D	research and development
RACC	Refiner Acquisition Cost of Crude in the United States
SNG	synthetic natural gas
TCF	trillion cubic feet
USGS	United States Geological Survey
WTI	West Texas Intermediate crude oil

Glossary

Access
The legal right to build transmission and distribution facilities on public and/or private land.

AECO (Alberta Energy Company)
Natural gas pricing point in Alberta, Canada.

Assessed Additional Resources
The sum of natural gas deposits estimated to be in-place (using accepted engineering models and analytical tools) that will become recoverable in the future at various assumed technology and price levels; current economic and operating conditions are insufficient to justify Proved Reserves status for this category.

Basis
The difference in price for a commodity at two different geographical locations. For natural gas, basis has meant the difference between the NYMEX futures contract at Henry Hub and the cash price at other market points. For natural gas, basis reflects the value of transportation costs, although regional supply and demand factors are also important. In the model analysis, it is the difference in gas prices between any two nodes at the same instant in time.

Brownfield Pipeline
Adding compression and/or looping to add capacity to an existing pipeline.

Capacity, Peaking
The capacity of facilities or equipment normally used to supply incremental gas or electricity under extreme demand conditions. Peaking capacity is generally available for a limited number of days at maximum rate.

Capacity, Pipeline
The maximum throughput of natural gas over a specified period of time for which a pipeline system or portion thereof is designed or constructed, not limited by existing service conditions.

City Gate
The point at which interstate and intrastate pipelines sell and deliver natural gas to local distribution companies.

Cogeneration
The sequential production of electricity and useful thermal energy from the same energy source. Natural gas is a favored fuel for combined-cycle cogeneration units, in which waste heat is converted to electricity.

Commercial
A sector of customers or service defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions.

Compression

Natural gas is compressed during transportation and storage. The standard pressure that gas volumes are measured at is 14.7 pounds per square inch (psi). Pipelines have compression stations installed along the line (one about every 100 miles) to ensure that the gas pressure is maintained while the gas is being transported. Current pipelines can carry compressed natural gas at nearly 1,500 psi, but most tend to operate at closer to 1,000 psi.

Cost of Service

The total amount of money, including return on invested capital, operation and maintenance costs, administrative costs, taxes, and depreciation expense, to provide a utility service.

Cubic Foot

The most common unit of measurement of gas volume; the amount of gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure, and water vapor.

Cumulative Production

The total volume of natural gas that has been withdrawn from producing reservoirs.

Delivery Point

A point on a pipeline's system at which it delivers natural gas that it has transported. The city gate is the most common delivery point for a pipeline or transportation company because this is where the gas is transferred to the LDC.

Distribution Line

Network-like pipeline that transports natural gas from a transmission line to an end-user's service line or to other distribution lines. Generally, large pipelines are laid in principle streets, with smaller lateral lines extending along side streets and connected at their ends to form a grid; sometimes lateral lines are brought to a dead end.

Electric

A sector of customers or service defined as generation, transmission, distribution, or sale of electric energy.

Electric Day

An arbitrary 24-hour period of time established by an electric utility for the operation of its system, usually beginning at midnight.

End-User

One who actually consumes energy, as opposed to one who sells or re-sells it.

FERC (Federal Energy Regulatory Commission)

The federal agency that regulates interstate gas pipelines and interstate gas sales under the Natural Gas Act.

Firm Customer

A customer who has contracted for firm service.

Firm Service

Service offered to customers under schedules or contracts that anticipate no interruptions, regardless of class of service, except for force majeure.

Fuel-Switching

Substituting one fuel for another based on price and availability. Large industries often have the capability of using either oil or natural gas to fuel their operation and of making the switch on short notice.

Fuel-Switching Capability

The ability of an end-user to readily change fuel type consumed whenever a price or supply advantage develops for an alternative fuel.

Gas Day

An arbitrary 24-hour period of time established by a pipeline for the operation of its system, often beginning at seven or eight o'clock in the morning.

Greenfield Pipeline

Development of a new pipeline.

Henry Hub

A pipeline interchange near Erath, Louisiana, where a number of interstate and intrastate pipelines interconnect through a header system operated by Sabine Pipe Line. The standard delivery point for the New York Mercantile Exchange natural gas futures contract.

Industrial

A sector of customers or service defined as manufacturing, construction, mining, agriculture, fishing, and forestry.

Interruptible Customer

A customer who does not have firm service.

Interruptible Service

Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the supplier under certain circumstances, as specified in the service contract.

Load Duration Curve

A curve of loads, plotted in descending order of magnitude, against time intervals for a specified period. The curve indicates the period of time load was above a certain magnitude. Load duration curves are profiles of system demand that can be drawn for a period of time (daily, monthly, yearly).

Load Factor

The ratio of average load to peak load during a specified period of time, expressed as a percent. The load factor indicates to what degree pipeline capacity has been utilized relative to total system capability.

Local Distribution Company

A company that obtains the major portion of its natural gas revenues from the operations of a retail gas distribution system and that operates no transmission system other than incidental connections within its own or to the system of another company.

Looping

Adding extra segments of pipe to add capacity to an existing pipeline.

Mains, Distribution

Pipes transporting gas within service areas to the point of connection with the service pipe.

Marketer (natural gas)

A company, other than the pipeline or LDC, that buys and resells gas or brokers gas for a profit. Marketers also perform a variety of related services, including arranging transportation, monitoring deliveries and balancing. An independent marketer is not affiliated with a pipeline, producer or LDC.

Mid-Continent

Natural gas pricing point for the Kansas/Oklahoma region.

New Fields

A quantification of resources estimated to exist outside of known fields on the basis of broad geologic knowledge and theory; in practical terms, these are statistically determined resources likely to be discovered in additional geographic areas with geologic characteristics similar to known producing regions, but which are as yet untested with the drillbit.

Nominal Dollars

Dollars that have not been adjusted for inflation.

Nonconventional Gas

Resources that are estimated to be contained in known strata of deposits requiring application of technologies different from those required to extract conventional high permeability gas reserves (i.e., shale gas, coalbed methane, tight gas, etc.).

Old Field Reserve Appreciation

Additional estimated conventional resources resulting from the recognition that currently booked Proved Reserves are conservative by definition and will continue to grow over time; based on historical experience, existing fields have been shown regularly to contain, and ultimately produce, significant additional quantities of natural gas in excess of initial proved reserve estimates.

Opal

Natural gas pricing point in Wyoming for the Rockies region.

Peak-Day Demand

The maximum daily quantity of gas used during a specified period, such as a year.

Peak Shaving

Methods to reduce the peak demand for gas or electricity. Common examples are storage and use of LNG.

Proved Reserves

The most certain of the resource base categories representing estimated quantities that 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; generally, these gas deposits have been "booked," or accounted for as assets on the SEC financial statements of their respective companies.

Real Dollars

Dollars in a particular year that have been adjusted for inflation to make financial comparisons in different years more valid. This NPC study generally adjusts dollars to the year 1998.

Receipt Point

A point on a pipeline's system at which it receives natural gas into its system.

Refiner Acquisition Cost of Crude Oil (RACC)

The cost of crude oil to the refiner, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs.

Regional Transmission Organization (RTO)

Voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning, expansion, and use on a regional and interregional basis.

Residential

The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lightning, refrigeration, cooking, and clothes drying.

Revenue

The total amount money received by a firm from sales of its products and/or services.

Shipper

One who contracts with a pipeline for transportation of natural gas and who retains title to the gas while it is being transported by the pipeline.

SoCal

Pipeline pricing point located in southern California.

Spot Market

Commodity transactions in which the transaction commencement is near term (e.g., within 10 days) and the contract duration is relatively short (e.g., 30 days).

Storage Service

A service in which natural gas is received by the seller of the service and held for the account of the customer for redelivery at later time. Storage services are typically utilized by customers to allow more even purchases or sales of natural gas throughout the year, despite variations in end-use demand. Storage service is also a critical element of the peak period deliverability of many interstate natural gas pipelines and distributors.

Supply Hub

A geographic location where supply is available from more than one basin.

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.

Tariff

A document filed by a regulated entity with either a federal or state commission. It lists the rates the regulated entity may charge to provide service to its customers as well as the terms and conditions that it will follow in providing that service.

Total All-Time Recovery

The sum of Total Remaining Resources plus Cumulative Production; the estimate of total natural gas that will ultimately be produced after all wells cease economic production.

Total Remaining Resources

The sum of Proved Reserves and Assessed Additional Resources; this term is often used interchangeably with "Total Resources" and refers to the total quantity of natural gas estimated to remain available for production.

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