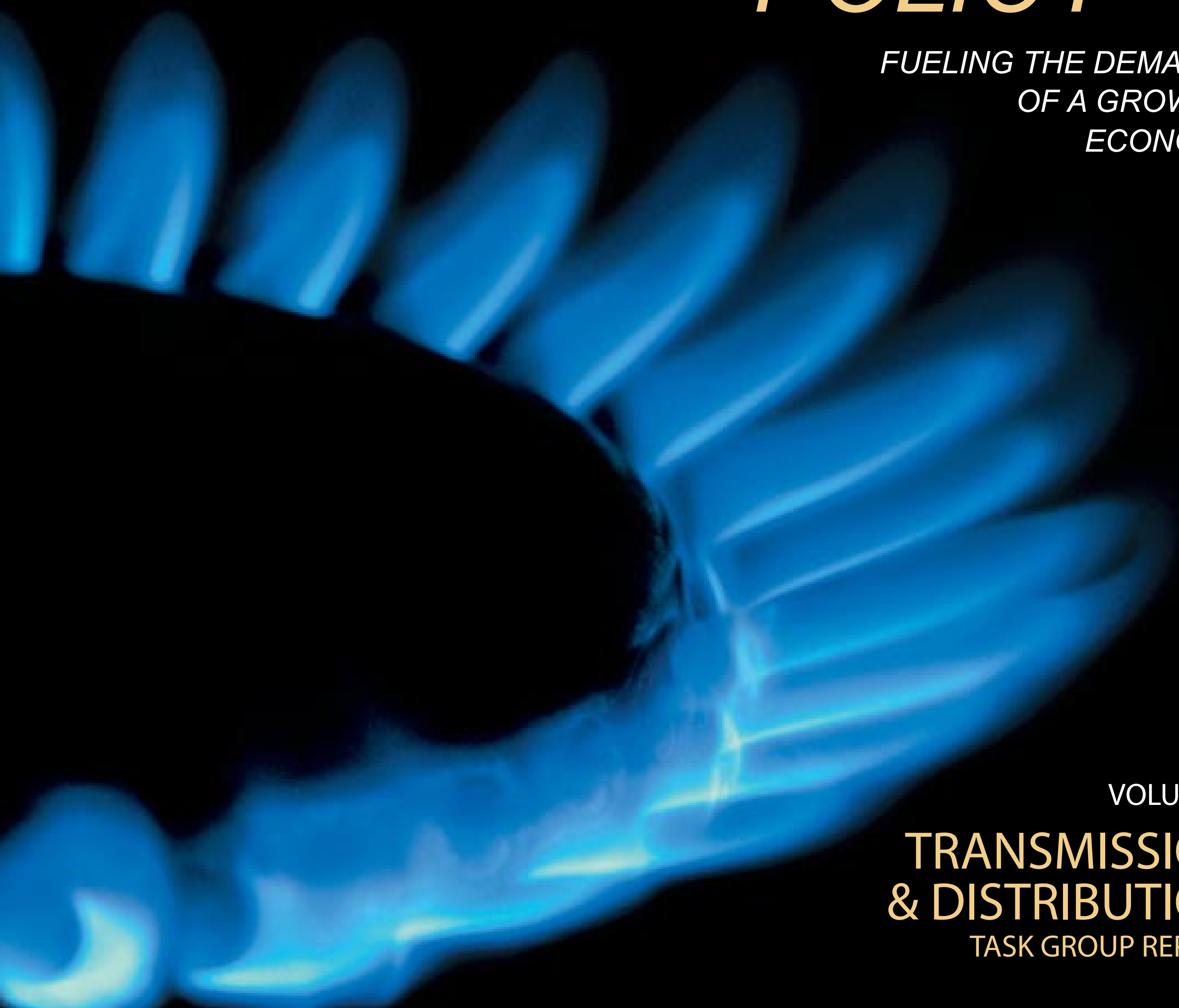
BALANCING NATURAL GAS POLICY

FUELING THE DEMANDS OF A GROWING ECONOMY



VOLUME V

TRANSMISSION & DISTRIBUTION
TASK GROUP REPORT

AND

LNG SUBGROUP REPORT

NATIONAL PETROLEUM COUNCIL

SEPTEMBER 2003

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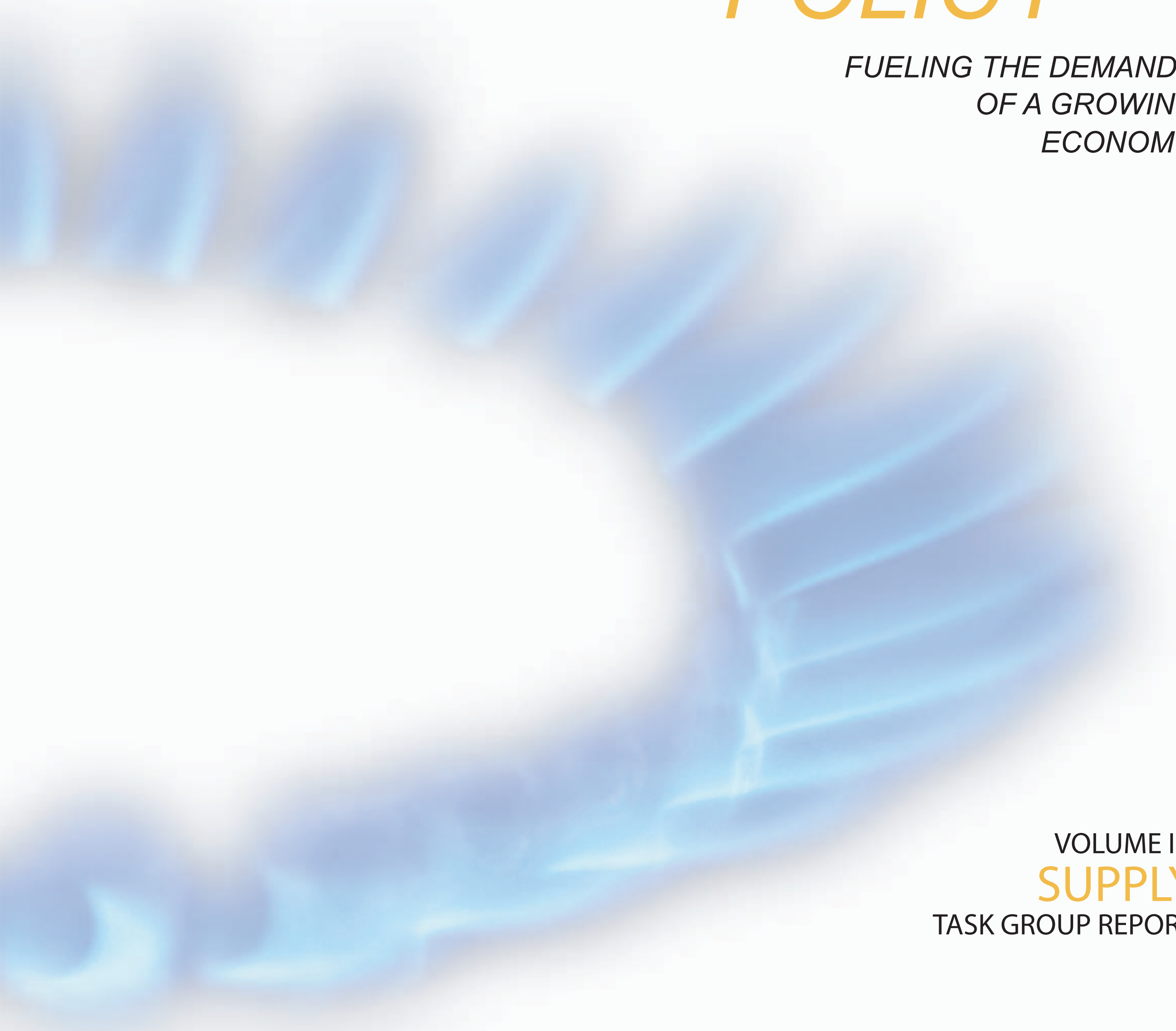

VOLUME IV

SUPPLY

TASK GROUP REPORT

SEPTEMBER 2003

NATIONAL PETROLEUM COUNCIL

COMMITTEE ON NATURAL GAS

BOBBY S. SHACKOULS, CHAIR

NATIONAL PETROLEUM COUNCIL

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U.S. DEPARTMENT OF ENERGY

Spencer Abraham, *Secretary*

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

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VOLUME V

PREFACE

Study Request

By letter dated March 13, 2002, Secretary of Energy Spencer Abraham requested the National Petroleum Council (NPC) to undertake a new study on natural gas in the United States in the 21st Century. Specifically, the Secretary stated:

> Such a study should examine the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It should also provide insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. Of particular interest is the Council's advice on actions that can be taken by industry and Government to increase the productivity and efficiency of North American natural gas markets and to ensure adequate and reliable supplies of energy for consumers.

In making his request, the Secretary made reference to the 1992 and 1999 NPC natural gas studies, and noted the considerable changes in natural gas markets since 1999. These included "new concerns over national security, a changed near-term outlook for the economy, and turbulence in energy markets based on perceived risk, price volatility, fuel-switching capabilities, and the availability of other fuels." Further, the Secretary pointed to the projected growth in the nation's reliance on natural gas and noted that the future availability of gas supplies could be affected by "the availability of investment capital and infrastructure, the pace of technology progress, access to the Nation's resource base, and new sources of supplies from Alaska, Canada, liquefied natural gas imports, and unconventional resources." (Appendix A contains the complete text of the Secretary's request letter and a description of the NPC.)

Study Organization

In response to the Secretary's request, the Council established a Committee on Natural Gas to undertake a new study on this topic and to supervise the preparation of a draft report for the Council's consideration. The Council also established a Coordinating Subcommittee and three Task Groups – on Demand, Supply, and Transmission & Distribution – to assist the Committee in conducting the study.

Bobby S. Shackouls, Chairman, President and Chief Executive Officer, Burlington Resources Inc., chaired the Committee, and Robert G. Card, Under Secretary of Energy, served as the Committee's Government Cochair. Robert B. Catell, Chairman and Chief Executive Officer, KeySpan Corporation; Lee R. Raymond, Chairman and Chief Executive Officer, Exxon Mobil Corporation; and Richard D. Kinder, Chairman and Chief Executive Officer, Kinder Morgan Energy Partners, L.P., served as the Committee's Vice Chairs of Demand, Supply, and Transmission & Distribution, respectively. Jerry J. Langdon, Executive Vice President and Chief Administrative Officer, Reliant Resources, Inc., chaired the Coordinating Subcommittee, and Carl Michael Smith, Assistant Secretary, Fossil Energy, U.S. Department of Energy, served as Government Cochair.

The transmission, distribution, and storage part of this volume of the report was prepared by the Transmission & Distribution Task Group and its subgroups. Scott E. Parker, President, Natural Gas Pipeline Company of America, Kinder Morgan Inc., chaired the Transmission & Distribution Task Group, and Mark R. Maddox, Principal Deputy Assistant Secretary, Fossil Energy, U.S. Department of Energy, served as Government Cochair. The Transmission & Distri-bution Task Group was assisted by three subgroups:

- Transmission Subgroup
- Distribution Subgroup
- Storage Subgroup.

The liquefied natural gas (LNG) part of this volume of the report was prepared by the LNG Subgroup of the Supply Task Group. John Hritcko, Jr., Vice President, Shell NA, LNG, Inc., led the LNG Subgroup. Mark A. Sikkel, Vice President, ExxonMobil Production Company, chaired the Supply Task Group, and Elena S. Melchert, Program Manager, Oil and Gas Production, Fossil Energy, U.S. Department of Energy, served as Government Cochair.

The members of the various study groups were drawn from the NPC members' organizations as well as from many other industries, non-governmental organizations, and government organizations. These study participants represented broad and diverse interests including large and small producers, transporters, service providers, financers, regulators, local distribution companies, power generators, and industrial consumers of natural gas. Appendix B contains rosters of the study's Committee, Coordinating Subcommittee, the Transmission & Distribution Task Group and its subgroups, and the Supply Task Group and its LNG Subgroup. In addition to the participants listed in Appendix B, many more people were involved in the work of the study's other task groups and subgroups as well as in regional and sector-specific workshops in the United States and Canada.

Study Approach

The study benefited from an unprecedented degree of support, involvement, and commitment from the gas industry. The breadth of support was based on growing concerns about the adequacy of natural gas supplies to meet the continuing strong demand for gas, particularly in view of the role of gas as an environmentally preferred fuel. The study addresses both the short-term and long-term outlooks (through 2025) for North America, defined in this study as consisting of Canada, Mexico, and the United States. The reader should recognize that this is a natural gas study, and not a comprehensive analysis of all energy sources such as oil, coal, nuclear, and renewables. However, this study does address and make assumptions regarding these competing energy sources in order to assess the factors that may influence the future of natural gas use in North America. The analytical portion of this study was conducted over a 12-month period beginning in August 2002 under the auspices of the Coordinating Subcommittee and three primary task groups.

The Transmission & Distribution Task Group analyzed existing and potential new infrastructure. Their analysis was based on the work of three subgroups (Transmission, Distribution, and Storage). Industry participants undertook an extensive review of existing and planned infrastructure capacity in North America. Their review emphasized, among other things, the need to maintain the current infrastructure and to ensure its reliability. Participants in the Transmission & Distribution Task Group included representatives from U.S. and Canadian pipeline, storage, marketing, and local distribution companies as well as from the producing community, the Federal Energy Regulatory Commission, and the Energy Information Administration.

The Supply Task Group developed a basin-by-basin supply picture, and analyzed potential new sources of supply such as liquefied natural gas (LNG) and Arctic gas. The Supply Task Group worked through five subgroups: Resource, Technology, LNG, Arctic, and Environmental/Regulatory/Access. Over 100 people participated. These people were drawn from major and independent producers, service companies, consultants, and government agencies. These working groups conducted 13 workshops across the United States and Canada to assess the potential resources available for exploration and development. Workshops were also held to examine the potential impact on gas production from advancing technology. Particular emphasis was placed on the commercial potential of the technical resource base and the knowledge gained from analysis of North American production performance history.

The Demand Task Group developed a comprehensive sector-by-sector demand outlook. This analysis was done by four subgroups (Power Generation, Industrial Utilization, Residential and Commercial, and Economics and Demographics). The task of each group was to try to understand the economic and environmental determinants of gas consumption and to analyze how the various sectors might respond to different gas price regimes. The Demand Task Group was composed of representatives from a broad cross-section of the power industry as well as industrial consumers from gas-intensive industries. It drew on expertise from the power industry to develop a broad understanding of the role of alternative sources for generating electric power based on renewables, nuclear, coal-fired, oil-fired, or hydroelectric generating technology. It also conducted an outreach program to draw upon the expertise of power generators and industrial consumers in both the United States and Canada.

Separately, two other groups also provided guidance on key issues that crossed the boundaries of the primary task groups. An ad hoc financial team looked at capital requirements and capital formation. Another team examined the issue of increased gas price volatility.

Due to similarities between the Canadian and U.S. economies and, especially, the highly interdependent character of trade in natural gas, the evaluation of natural gas supply and demand in Canada and the United States were completely integrated. The study included Canadian participants, and many other participating companies have operations in both the United States and Canada. For Mexico, the evaluation of natural gas supply and demand for the internal market was less detailed, mainly due to time limitations. Instead, the analysis focused on the net gas trade balances and their impact on North American markets.

As in the 1992 and 1999 studies, econometric models of North American energy markets and other analytical tools were used to support the analyses. Significant computer modeling and data support were obtained from outside contractors; and an internal NPC study modeling team was established to take direct responsibility for some of the modeling work. The Coordinating Subcommittee and its Task Groups made all decisions on model input data and assumptions, directed or implemented appropriate modifications to model architecture, and reviewed all output. Energy and Environmental Analysis, Inc. (EEA) of Arlington, Virginia, supplied the principal energy market models used in this study, and supplemental analyses were conducted with models from Altos Management of Los Altos, California.

The use of these models was designed to give quantified estimates of potential outcomes of natural gas demand, supply, price and investment over the study time horizon, with a particular emphasis on illustrating the impacts of policy choices on natural gas markets. The results produced by the models are critically dependent on many factors, including the structure and architecture of the models, the level of detail of the markets portrayed in the models, the mathematical algorithms used, and the input assumptions specified by the NPC study task groups. As such, the results produced by the models and portrayed in the NPC report should not be viewed as forecasts or as precise point estimates of any future level of supply, demand, or price. Rather, they should be used as indicators of trends and ranges of likely outcomes stemming from the particular assumptions made. In particular, the model results are indicative of the likely directional impacts of pursuing particular public policy choices relative to North American natural gas markets.

This study built on the knowledge gained and processes developed in previous NPC studies, enhanced those processes, created new analytical approaches and tools, and identified opportunities for improvement in future studies. Specific improvements included the following elements developed by the Supply Task Group:

- A detailed play-based approach to assessment of the North American natural gas resource base, using regional workshops to bring together industry experts to update existing assessments. This was used in two detailed descriptive models, one based on 72 producing regions in the United States and Canada, and the other based on 230 supply points in the United States, Canada, and Mexico. Both models distinguished between conventional and nonconventional gas and between proved reserves, reserve growth, and undiscovered resource.

- Cost of supply curves, including discovery process models, were used to determine the economically optimal pace of development of North American natural gas resources.

- An extensive analysis of recent production performance history, which clearly identified basins that are maturing and those where production growth potential remains. This analysis helped condition the forward-looking assumptions used in the models.

- A model to assess the impact of permitting in areas currently subject to conditions of approval.

- A first-ever detailed NPC view and analysis of LNG and Arctic gas potential.

The Demand Task Group also achieved significant improvements over previous study methods. These improvements include the following:

- Regional power workshops and sector-specific industrial workshops to obtain direct input on consuming trends and the likely impact of changing gas prices.

- Ongoing detailed support from the power industry for technology and cost factors associated with current and future electric power generation.

- Development of a model of industrial demand focusing on the most gas-intensive industries and processes.

Study Report

Results of this 2003 NPC study are presented in a multi-volume report as follows:

- Volume I, *Summary of Findings and Recommendations*, provides insights on energy market dynamics as well as advice on actions that can be taken by industry and government to ensure adequate and reliable supplies of energy for American consumers. It includes an Executive Summary of the report and an overview of the study's analyses and recommendations.

- Volume II, *Integrated Report*, contains discussions of the results of the analyses conducted by the three Task Groups: Demand, Supply, and Transmission & Distribution. This volume provides further supporting data and analyses for the findings and recommendations presented in Volume I. It addresses the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It provides insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. It also expands on the study's recommended policy actions. This volume presents an integrated outlook for natural gas demand, supply, and transmission in the United States, Canada, and Mexico under two primary scenarios and a number of sensitivity cases.

  The demand analysis provides an understanding of the economic and environmental determinants of natural gas consumption to estimate how the industrial, residential/commercial, and electric power sectors may respond under different conditions. The supply analysis develops basin-by-basin resource and cost estimates, presents an analysis of recent production performance, examines potential technology improvements, addresses resource access issues, and examines potential supplies from traditional areas as well as potential new sources of supply such as liquefied natural gas and Arctic gas. The transmission, distribution, and storage analysis provides an extensive review of existing and planned infrastructure in North America emphasizing, among other things, the need to maintain the current infrastructure and to ensure its reliability.

- *Task Group Report Volumes and CD-ROMs* include the detailed data and analyses prepared by the Demand, Supply, and Transmission & Distribution Task Groups and their subgroups, which formed the basis for the development of Volumes I and II. Information on the study's computer modeling activities is also included. 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 or approve all of the statements and conclusions contained in these documents but, rather, to approve the publication of these materials as part of the study process. These documents are provided as follows:

  – Volume III, *Demand Task Group Report*, provides in-depth discussions and analyses of economic and demographic assumptions; consumption in the industrial, residential, commercial, and electric power sectors; and uncertainties/sensitivities.

- Volume IV, *Supply Task Group Report*, provides in-depth discussions and analyses of resource assessment, cost methodology, production performance, technology improvements, access issues, and arctic developments.
- Volume V, *Transmission & Distribution Task Group and LNG Subgroup Reports*, provides in-depth discussions and analyses of LNG imports and transmission, distribution, and storage infrastructures. (While the LNG Subgroup operated under the Supply Task Group, its report is provided with that of the Transmission & Distribution Task Group due to the interrelationship of their infrastructures and issues.)
- *CD-ROMs* are available as part of the documentation of the Task Group Reports. One CD contains further input/output on a regional basis for the study's principal modeling activities. That CD also contains digitized maps, which were used in assessing the potential impact of conditions of approval for access to key Rocky Mountain resource areas. Another CD contains the input data developed by the NPC for use in the study's supplemental modeling activities.

A form for ordering additional copies of the report volumes can be downloaded from the NPC website, http://www.npc.org. Pdf copies of Volumes I through V also can be viewed and downloaded from the NPC website.

Retrospectives on 1999 Study

In requesting the current study, the Secretary noted that natural gas markets had changed substantially since the Council's 1999 study. These changes were the reasons why the 2003 study needed to be a comprehensive analysis of natural gas supply, demand, and infrastructure issues. By way of background, the 1999 study was designed to test the capability of the supply and delivery systems to meet the then-public forecasts of an annual U.S. market demand of 30+ trillion cubic feet early in this century. The approach taken in 1999 was to review the resource base estimates of the 1992 study and make any needed modifications based on performance since the publication of that study. This assessment of the natural gas industry's ability to convert the nation's resource base into available supply also included the first major analytical attempt to quantify the effects of access restrictions in the United States, and specifically the Rocky Mountain area. Numerous government agencies used this work as a starting point to attempt to inventory various restrictions to development. This access work has been further expanded upon in the current study. Further discussions of the 1999 analyses are contained in the Task Group Reports.

The 1999 report stated that growing future demands could be met if government would address several critical factors. The report envisioned an impending tension between supply and demand that has since become reality in spite of lower economic growth over the intervening time period. On the demand side, government policy at all levels continues to encourage use of natural gas. In particular, this has led to large increases in natural gas-fired power generation capacity. The 1999 study assumed 144 gigawatts of new capacity through 2015, while the actual new capacity is expected to exceed 200 gigawatts by 2005. On the supply side, limits on access to resources and other restrictive policies continue to discourage the development of natural gas supplies. Examples of this are the 75% reduction in the Minerals Management Service's Eastern Gulf Lease Sale 181 and the federal government's "buying back" of the Destin Dome leases off the coast of Florida.

The maturity of the resource base in the traditional supply basins in North America is another significant consideration. In the four years leading up to the publication of this study, North America has experienced two periods of sustained high natural gas prices. Although the gas-directed rig count did increase significantly between 1999 and 2001, the result was only minor increases in production. Even more sobering is the fact that the late 1990s was a time when weather conditions were milder than normal, masking the growing tension between supply and demand.

In looking forward, the Council believes that the findings and recommendations of this study are amply supported by the analyses conducted by the study groups. Further, the Council wishes to emphasize the significant challenges facing natural gas markets and to stress the need for all market participants (consumers, industry, and government) to work cooperatively to develop the natural gas resources, infrastructure, energy efficiency, and demand flexibility necessary to sustain the nation's economic growth and meet environmental goals.

SUPPLY TASK GROUP

LNG SUBGROUP REPORT

LNG SUBGROUP REPORT

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SUPPLY TASK GROUP

LNG SUBGROUP REPORT

I. Executive Summary

A Liquefied Natural Gas (LNG) Subgroup was formed as part of the NPC Supply Task Group to develop a short- and long-term (2025) outlook for North American LNG imports. In addition to developing an outlook for imports of LNG, the LNG Subgroup developed a "primer" on LNG. This primer describes the LNG value chain, summarizes the history of LNG, presents an outlook for global LNG supply and demand, and provides a summary of competitive supply cost and prospects for permitting and constructing terminals in the United States. This LNG report summarizes the issues facing U.S. terminal development that may impact the level of LNG imports and offers recommendations.

A. Study Results and Recommendations

The study concludes that LNG, which now supplies about one percent of U.S. demand, will become a major source of gas supply for North America. By 2025, it is estimated to account for 14-17% of U.S. demand. LNG also adds diversity beyond traditional indigenous sources by linking the U.S. supply system to the rapidly developing global LNG market.

Three LNG model scenarios were developed including the Reactive Path scenario (significant new LNG imports/terminals), the Balanced Future scenario (significant new LNG imports/terminals and a streamlined regulatory process), and a Low Sensitivity case (public opposition). Each of these cases assumes the four existing LNG terminals plus expansions will be fully utilized and that multiple new terminals will be built to meet the growing natural gas demand.

Growth in North American LNG imports will be gradual, but it will increase steadily as new LNG supplies are developed and new LNG terminals are built. The pace will be driven by (1) the time required to secure permits for new terminals (assumed at 2 years), (2) time to construct those terminals (3 years), (3) the availability of the locations for new LNG terminals, and (4) access to global LNG supply and ships.

LNG projects are large; they have long lead times and face major barriers to development. As a result, the cost of LNG is higher than the cost of gas from some domestic sources. Nevertheless, LNG can become a significant and economic source of long-term supply for the United States. However, LNG supplies will only be attracted to North America if new LNG terminals can be built to receive them.

Although in recent years federal policy and legislation has eased the regulatory review process for new LNG import projects, there are still actions that federal, state and local governments and agencies can take to increase LNG imports. These include:

- Improving coordination among federal, state, and local agencies to expedite facility permitting
- Establishing specified timeframes for processing LNG-related permit applications
- Together with local communities and authorities, undertaking public education regarding the safety and the benefits of LNG
- Funding and staffing regulatory agencies so that permitting and regulatory needs can be achieved in a timely manner

- Within the limits of safe operations, facilitating updates to interchangeability standards and reassessment of current pipeline specifications regarding gas quality
- Reviewing and, if necessary revising, LNG industry standards/specifications.

B. LNG Overview

LNG is the liquid form of natural gas that has been cooled to a temperature of –256°F or (–161°C) and maintained at atmospheric pressure. It is an odorless, colorless, non-corrosive, and non-toxic liquid. The process for liquefying natural gas reduces the volume of the gas to approximately 1/600th of its original volume. This process enables it to be transported economically in specially designed ocean vessels throughout the world.

The LNG industry is often described by the expression the "LNG chain." This chain is a reference to the fact that LNG projects are large and require critical mass and alignment throughout the many phases of supply production, liquefaction, transportation, regasification, and distribution to consumers. These investments must be large enough to achieve economies of scale and must be tightly coordinated if the overall project is to be economic. LNG projects require massive natural gas reserves (7 to 10 TCF), produce significant volumes (0.5 to 1.0 BCF/D), and require investments as large as 4 to 10 billion dollars. Also, because of the large scale of these projects, and the considerable financial risk involved in undertaking them, a secure market for the natural gas is usually a necessary condition for their development. That is the reason why most of the world's LNG is sold under long-term contracts (20 to 25 years), although short-term and spot-market sales are being introduced as markets mature.

LNG is already a significant supply source for many countries in the world. However, gas reserves that provide the gas for most LNG supply projects are located where there is minimal local demand for natural gas or in areas far from pipeline transportation systems. Reserves located near demand areas are typically connected to those areas by a network of pipelines. The LNG industry has been steadily growing since the first LNG flowed from Algeria to Europe in 1964. Propelled by growing gas demand in Asia and countries where domestic production is inadequate to cover local needs, the global LNG trade has grown at an annual rate of about 8% since the late 1970s. While the major established markets of Japan and Korea are showing signs of maturity, new and developing markets in the United States and Europe are expected to support continued demand growth at an annual rate of 6-10%, which would double the size of the industry by 2010.

Initially, most LNG was produced in Africa and Asia and, more recently, the Middle East and Trinidad. Small amounts of LNG were produced in the late 1960s in Algeria, Libya, and the United States. In the 1970s, developments in four Asia-Pacific countries (Brunei, Indonesia, Malaysia, and Australia) were initiated which have since grown significantly over time. In the late 1990s, major supply sources emerged in the Middle East and the Atlantic Basin. In the Middle East, LNG projects were developed in Qatar and Oman, and in the United Arab Emirates. In the Atlantic basin, new projects emerged in Trinidad and Tobago and Nigeria. Significant resources remain in these countries and multiple new projects have been announced.

The global LNG industry has demonstrated an excellent safety record throughout its almost 40-year history. This is the result of an emphasis on safety and on attention to detail in engineering, construction and operations. This emphasis has been codified in stringent safety standards that have been adopted by many countries, including the United States, Japan, Australia, and European nations.

C. LNG in the United States

LNG imports to the United States started in 1970 at the terminal in Everett, Massachusetts. U.S. import volumes, predominately from Algeria, remained low until 1978 when terminals in Cove Point, Maryland and Elba Island, Georgia were completed. LNG imports reached a peak of 253 BCF in 1979, or about 1.3% of total U.S. gas consumption. The fourth U.S. LNG terminal at Lake Charles, Louisiana was completed in 1981. In the 1980s, because of falling U.S. natural gas demand and competition from lower-priced pipeline gas, LNG imports declined rapidly. Consequently, in 1980 the Elba Island and Cove Point terminals were mothballed. In 1983 the Lake Charles terminal was also taken out of service after only two years in operation. The industry hit a low in 1986-1987 when almost no LNG was imported. With the re-opening of Lake Charles in 1989, volumes slowly returned and in the 1990s averaged about 50 BCF per year.

Significant changes in the market began in 1999. Higher demand for gas, higher prices, changes in the regulatory environment, and new, lower-cost sources of supply led to a substantial increase in LNG imports. The two mothballed terminals were re-opened (Elba Island in 2001, and Cove Point in 2003), and imports from Qatar and Trinidad and Tobago entered the market for the first time. In 2002, these terminals imported nearly 230 BCF or about one percent of U.S. gas demand. The number of countries supplying LNG to the U.S. market has also increased.

The industry activity has picked up substantially and its potential has increased. Expansions have been announced at three of the existing U.S. terminals. An onshore terminal (Cameron LNG) recently received a construction permit (the first since 1981), and the U.S. Coast Guard is reviewing two proposed offshore terminals. Over 30 new North American terminal projects have been announced during the past few years, and new supply deals have also been announced. The four existing terminals are fully functioning once again, although these terminals will not be fully utilized because current sources of supply and the existing shipping fleet is mostly dedicated to other markets. Over time, as new supplies come on stream and new LNG ships are constructed, that will change.

New potential import terminal projects have many hurdles to overcome including permitting, obtaining supply, shipping, financing, and other issues. In this study, the LNG import scenarios were developed based on the following considerations:

- North American market demand and pricing
- International supply availability and cost
- Availability of LNG tankers
- The number, location, and timing of terminal expansions
- Regulatory and permitting issues
- Support from local communities and authorities for new facilities.

The scenario called Reactive Path assumes seven new terminals are built in North America (five in the United States) and that three of those terminals are then expanded. Together with the existing terminals and their expansions, this scenario indicates an increase in imports from 0.6 BCF/D (2003) to 12.5 BCF/D by 2025. Streamlining the permitting process, as in the Balanced Future scenario, together with additional two new terminals, could increase imports to 15 BCF/D by 2025. Fewer new terminals can have a significant effect on supply availability. The Low Sensitivity case assumes public opposition will allow only two new terminals to be built in the United States. The effect of this case is to increase average (2003) Henry Hub natural gas prices by about $0.70 per million Btu through 2025 on the Reactive Path projection.

D. Elements of Success

There are several reasons why LNG supply is now competitive in the U.S. market when only a short time ago it was not. The first of these is a reduction in supply cost, a result of significant reductions in the cost of supply at every stage in the LNG value chain. For example, significant cost reductions from new technology and economies of scale have occurred in the LNG liquefaction process, particularly over the past 15 years. The industry has witnessed large increases in the size of new LNG liquefaction plants (referred to as trains). The traditional liquefaction train size was 2 million tonnes per annum (MTA) or about 260 million cubic feet per day; newly constructed trains are now as large as 4.8 MTA or about 550 million cubic feet per day, and larger train sizes have been announced. These larger trains have resulted in significant reductions in the cost of liquefaction. Equally large cost reductions, almost 40% since 1996, have also been achieved in shipping, mainly because of new competition from Korean shipyards. New shipyards in China will assist in maintaining this competitive environment for some time.

Another reason why LNG is now poised to enter the U.S. market is that new sources of supply are being developed. These include new developments as well as expansions of existing projects. Announced supplies from the Atlantic Basin, the Middle East, and the Asia Pacific region are competitive in U.S. markets. These potential supplies have a full LNG chain cost in the $2.00 to $5.50 per million Btu price range, with a large percentage of the supply able to deliver LNG into the U.S. economically at a cost in the $2.00 to $4.00 per million Btu range.

Reserves of natural gas that are used to produce LNG around the world vary greatly in quality and in the composition of the natural gas stream. At present, much of the international LNG production has a heat content that is above U.S. pipeline limits. This problem can be, and is being, addressed. The ability of the U.S. market to accommodate a wide variation in gas composition will result in more supply options for the U.S. gas buyers.

A critical element for increasing U.S. imports will be construction of several new regasification terminals. To achieve the aggressive outlook represented in the Balanced Future scenario, the permitting process will need to be streamlined. Expediting the approval process throughout all agencies (federal, state, and local) is critical for overcoming the many obstacles that may surface, including local opposition. In addition, public education about LNG is needed in order to communicate to the public that LNG is safe and that it is critically important to the health of the national economy.

LNG is set to become an important supply source for growing North America natural gas demand. While not a "quick-fix" for short-term demand, LNG can provide a long-term, growing, and economical source of natural gas that will enhance the North America supply mix.

II. LNG Overview

A. What is LNG?

LNG or Liquefied Natural Gas is the liquid form of natural gas that has been cooled to a temperature of –256°F or (–161°C) and maintained at atmospheric pressure. It is an odorless, colorless, non-corrosive and non-toxic liquid. Natural gas is liquefied through a refrigeration process that reduces the volume of the gas to approximately 1/600th its original size. This process enables it to be transported globally in specially designed ocean vessels.

LNG is typically produced in countries or regions that have significant natural gas reserves but very little local demand. These areas also tend to be far from natural gas pipelines that could transport the gas to market. The manufacture of LNG is one way to overcome these market limitations.

B. The LNG Value Chain

The LNG industry is often described using the metaphor of an "LNG chain," as shown in Figure L-1. This is a reference to the fact that LNG projects consist of large interdependent investments that must be closely coordinated to be successful. All links of the chain must work together for natural gas to be produced, liquefied and exported, transported, imported, regasified and sold as natural gas to consumers. LNG projects require significant reserves (4 to 10 TCF); they must produce substantial volumes (500 to 1,000 MMCF/D), and they may require end-to-end investments of 2 to 5 billion dollars for up to a 1.0 BCF/D facility. The large initial capital investment implies an extended payback period, and corresponding financial risk, which means that most of the world's LNG is sold under long-term contracts (typically 20 to 25 years). There are, however some short-term and medium-term markets and, occasionally, there are sales of individual cargoes.

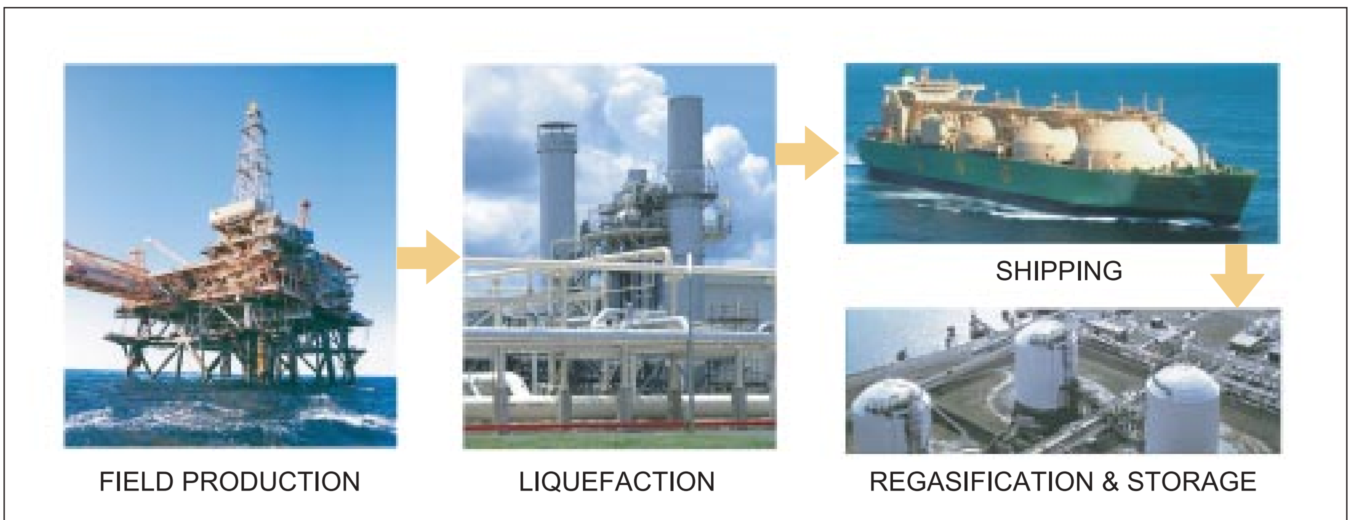


Figure L-1. The LNG Value Chain

A briefing paper on LNG can be found at http://www.energy.uh.edu/lng/ (University of Houston, Institute for Energy, Law & Enterprise, *Introduction to LNG*, January 2003).

C. The Global History of LNG

The LNG industry has been growing steadily since 1964 when the first cargo was delivered from Algeria to Europe. Propelled by growing gas demand in Asia and other countries where domestic production is inadequate to cover local needs, LNG production has grown steadily so that by 2002 it accounted for 6.1% of global natural gas demand.

Historically as many as twelve countries have imported LNG: three in Asia, seven in Europe, one in North America (excluding Puerto Rico, which is counted as a U.S. territory), and recently the Dominican Republic. LNG was first delivered to the United Kingdom in 1964 and to France the following year. Spain and Italy began importing LNG in the 1970s, followed by Belgium (1982), small amounts to West Germany in 1986-1987, and Turkey in 1994. Asia, which consumes about 70% of all LNG production, is by far the largest importer of LNG. Japan received its first deliveries of LNG in 1969; Korea followed in 1986, and Taiwan in 1990. North American imports began in the United States in 1970, and recently Puerto Rico (2000) and the Dominican Republic (2003) began to import LNG.

Worldwide, as illustrated in Figure L-2, LNG imports have grown from less than one MTA in 1964 to more than 100 MTA in 2002. LNG volumes are typically measured in millions of metric tonnes per year, which is equivalent to about 132 million cubic feet per day. Historically, Asia has been the dominant LNG importer, followed by Europe and, to a much lesser extent, North America.

Due to the capital-intensive character of the LNG industry only a relatively small number of companies or national governments participate in it. LNG was at one time limited to very few projects but, because of advances in technology that have identified new natural gas fields and reduced production and exploration costs, many new LNG projects are being developed or considered. There are currently 12 countries that export LNG. These include four in Asia, three in Africa, three in the Middle East, one in North America, and one in South America. Many new LNG supply

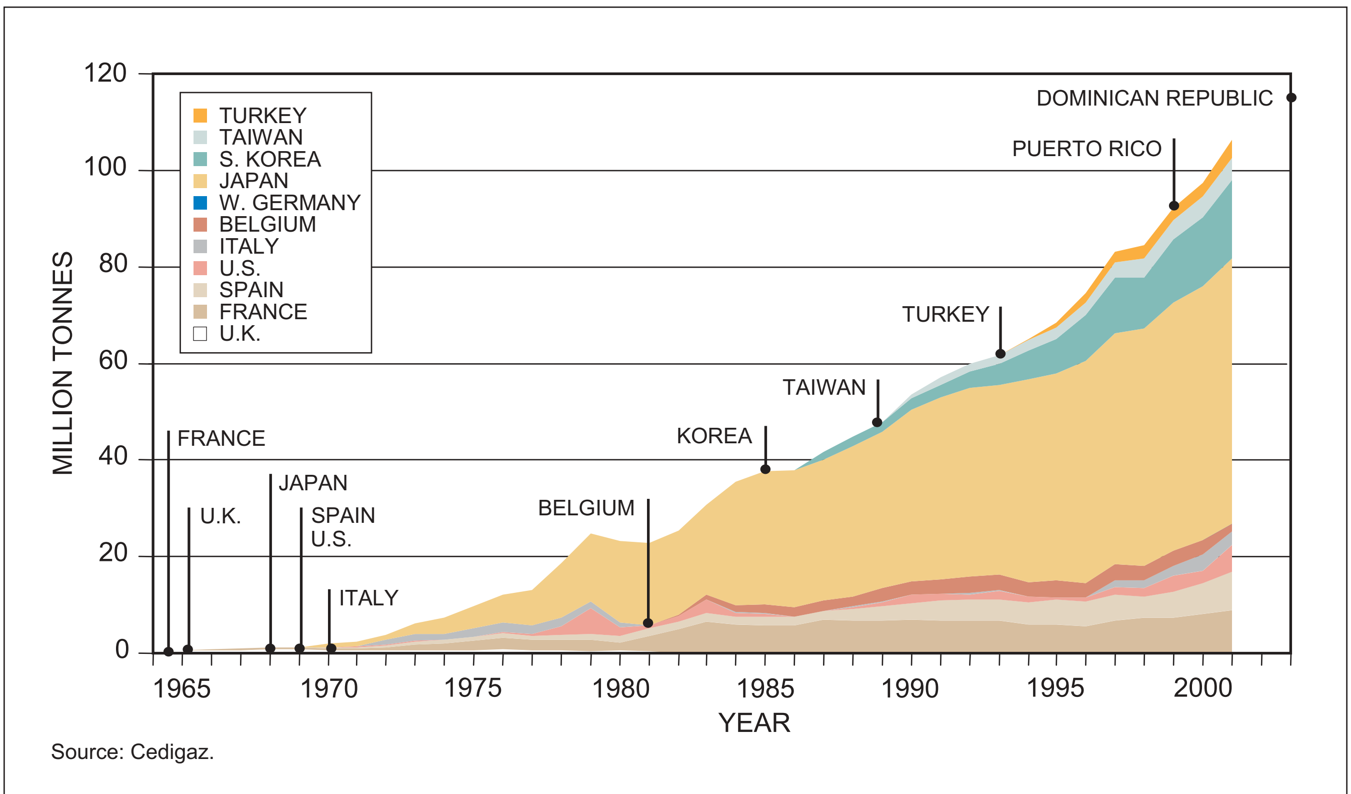


Figure L-2. Historical LNG Demand – LNG Import Countries and their Start Dates projects are under construction or have been proposed. These locations are shown in Figure L-3.

The first country to export LNG was Algeria in 1964 followed by the United States (from Alaska) in 1969. During the 1970s, export facilities were developed in Libya (1970), Brunei (1972), Abu Dhabi (1977), and Indonesia (1977). Two Asian projects were initiated in the 1980s, Malaysia (1983) and Australia (1989). The 1990s witnessed the addition of new projects in Qatar (1996, 1999), Oman (2000), Trinidad (1999, 2002-2003), and Nigeria (1999, 2002).

These liquefaction facilities typically consisted of two separate liquefaction facilities, each referred to as an LNG train. Many of these projects were later expanded. Throughout its 30-plus-year history, the LNG industry has demonstrated significant growth and is set to expand its global reach.

D. LNG Safety

The global LNG industry has an excellent safety record throughout its 40-year history. This record arises from an emphasis on safety and attention to detail in engineering, construction, and operations in all aspects of the LNG chain. This emphasis has been codified in stringent safety standards, which have been adopted by countries such as the United States, Japan, Australia, and European nations.

The main hazards associated with LNG are its low temperature, its flammability of vaporized gas if released into the environment, and its dispersion characteristics as a gas. As a liquid, LNG is neither flammable nor explosive. It therefore poses little risk as long as it is contained in piping or storage tanks. All piping and storage tanks are made from materials that will maintain their strength at cryogenic temperature. The tanks are also insulated to help maintain the temperature of the LNG while protecting workers and surrounding materials from exposure.

LNG ships are double-hulled and specially designed so that the LNG is stored in special containment systems that are only slightly above atmospheric pressure and at –256°F. These vessels are designed to protect the cargo tanks and to prevent leakage or rupture in an accident. The International Maritime Organization has developed international standards for the construction and operations of all ships, including LNG ships.

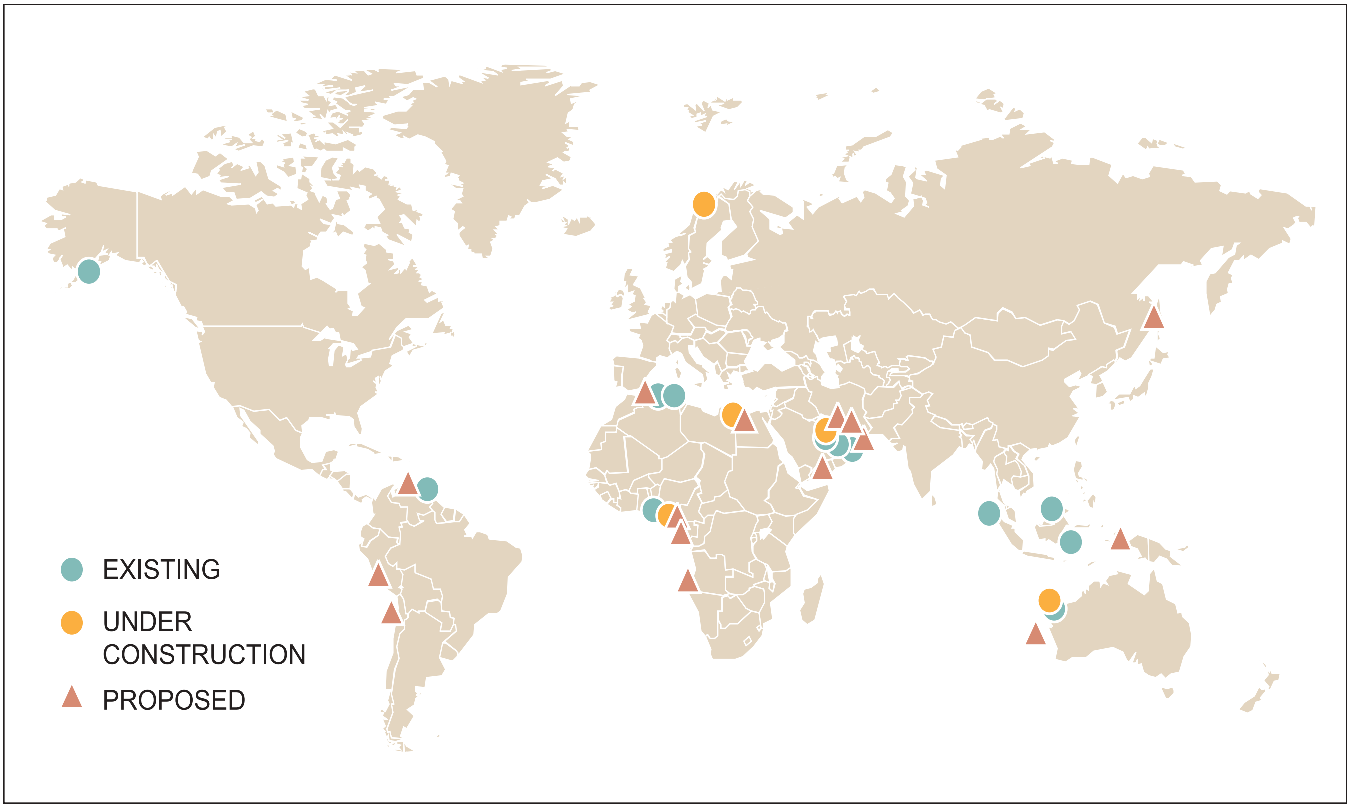


Figure L-3. Global LNG Supply

If LNG leaks out accidentally or if there is a release for any reason, the LNG will be exposed to warmer surfaces (such as air, water, or ground) and it will begin to evaporate rapidly, turning back into its original gaseous form. The natural gas formed from evaporation of LNG is not toxic. If LNG vaporizes in high concentrations and if in an unventilated or inside a confine area, it can cause asphyxiation due to insufficient oxygen. The gas is flammable when mixed with air in concentrations between 5% and 15% by volume. Between these limits, called the flammability limits, the gas will ignite if exposed to an ignition source. In unconfined areas, the gas, if ignited, will burn but will not detonate. If there is no ignition source, it will continue to mix with the air and ultimately dissipate.

If the gas ignites close to the source of the leak or release, the result will be a fire burning at the release site. The size of the fire will depend on the amount of LNG that is released, where it is released (on land or water), as well as environmental conditions (wind, temperature, relative humidity, waves, etc.). The largest potential release at an onshore facility would be from a massive failure of a storage tank. In that event the contents would spill out into a berm surrounding the tank. Regulations require a thermal exclusion zone around the impoundment that is large enough that the heat from an LNG fire within the berm will not exceed specified limits at the terminal boundary. The thermal exclusion zone must be owned or controlled by the operator of the LNG facility. The formula and heat flux factors used for calculation of the exclusion zone are described in the U.S. Code of Federal Regulation (CFR), 49 CFR Part 193. All current and prospective LNG sites are required to adhere to the National Fire Protection Association NFPA 59A standards, which specify substantial protection measures in the unlikely event of a storage tank breach.

If LNG is released and the gas formed does not ignite close to the source of the release, it will form a visible cloud. The cloud will be visible because the low temperature of the gas condenses the water vapor in the air, forming a fog. The size of the cloud will depend on, among other things, the quantity of LNG released, the rate at which it is released, the surface onto which it is released, and the atmospheric and wind conditions at the time of the release. Initially, the cloud will be heavier than air and will remain close to the surface; as it warms, the gas will become lighter than air and will rise and dissipate. The portion of the cloud that contains between 5% and 15% natural gas will be flammable; if ignited, it will burn back to the source of the release and will continue to burn there.

The risks associated with LNG have been extensively tested and researched by industry, independent scholars, the U.S. Coast Guard, and other government agencies. This research has contributed to many of the standards and regulations now in place and to the design and operating standards of the industry.

Because of the emphasis on safety, since 1944 there has not been an accident involving LNG that has affected a member of the public anywhere in the world. The overall incident rate for LNG facilities is also lower than other industrial operations. The industry has made more than 40,000 LNG voyages covering more than 60 million miles without major accidents or safety issues in port or on the high seas.[1] Terminals have also had no major reported incidents for almost 25 years.

A briefing paper on LNG Safety can be found at http://www.energy.uh.edu/lng/ (University of Houston, Institute for Energy, Law & Enterprise, *LNG Safety and the Environment,* September 2003).

III. Why LNG Now?

LNG is now viable in the U.S. market for two reasons. First, natural gas prices are higher and potential new sources of low-cost domestic supplies appear to be limited. Second, advances in LNG producing technology and market competition have reduced supply-chain costs (liquefaction, shipping, and regasification), allowing LNG to compete against domestic sources of supply.

For the first 40 years of its operations, the LNG industry financed its projects with the help of long-term supply contracts, mostly with "triple A" rated Japanese and Korean utilities. The industry has now entered a second phase in its evolution – a phase characterised by more potential customers with varied credit risk profiles. In addition, new projects in the Atlantic Basin and the Middle East are creating new trade patterns.

There are many other changes occurring as well. The regulatory framework of the natural gas industry

1 University of Houston, Institute for Energy, Law & Enterprise, *LNG Safety and the Environment,* September 2003.

has been, or is being, restructured in many countries, and traditional markets are being deregulated. One result is that LNG is gaining access to new markets and there is opportunity to compete with pipeline gas in southern Europe and the United States. More flexible sales contracts are also emerging. These changes are subjecting the LNG industry to increased competition, which will continue to exert pressure on the industry to reduce its costs of production. Already, full chain costs have fallen by approximately 30% since the early 1990s, and a similar reduction is expected by the end of the decade.

A. Cost Reductions in the LNG Supply Chain

The cost reductions have come in two main areas: (1) LNG production and (2) shipping.

1. LNG Production

The first natural gas liquefaction trains, which came on line in 1964, produced around 350,000 tonnes per annum of LNG. Since that time, liquefaction trains have continued to grow in size, reaching 4.7 MTA with the Qatar RasGas Train 3 design that will start up in January 2004. This continued growth in train size has allowed LNG producers to achieve considerable savings on a unit of production basis (i.e., dollars per tonne per annum of annual plant capacity). This trend is set to continue as another project in Qatar scheduled to start up in 2007, has announced a new two train project which will have capacities of 7.8 MTA for each train.

These evolutions in train size have been brought about through continued development in refrigerant compressors, their drivers, and the heat transfer equipment used to liquefy the gas. The drivers have gone from steam turbines in the early plants, to General Electric (GE) Frame 3, Frame 5C, and 5D gas turbines, to Frame 6 and Frame 7 drivers being used in the most modern plants currently in operation. The recently announced 7.8 MTA train in Qatar will employ three GE Frame 9E gas turbines per train, with each turbine developing an ISO rating of 120,000 KW.

Cost savings have also been achieved through competition of manufacturers. As illustrated in Figure L-4, liquefaction typically represents 20% to 30% of the cost of producing and delivering LNG.

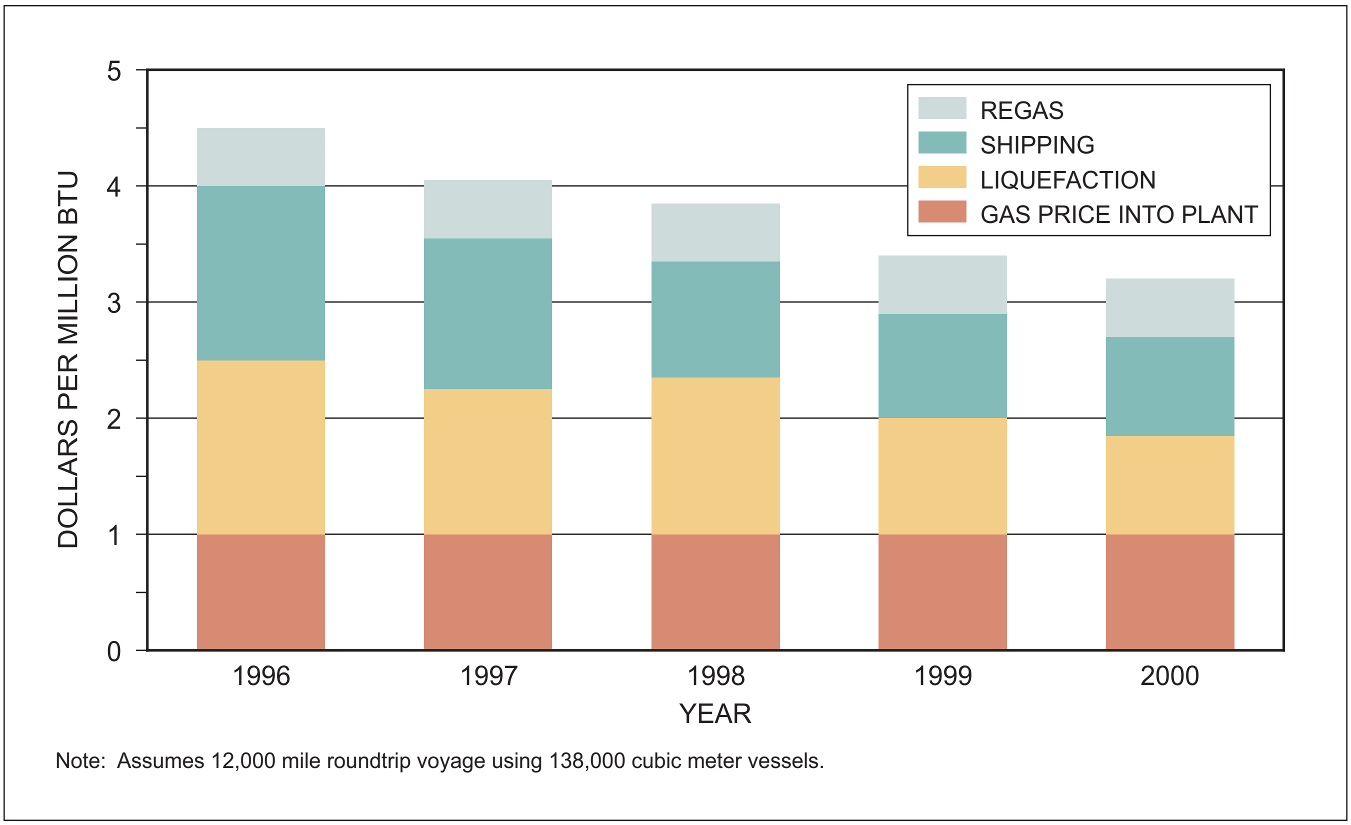


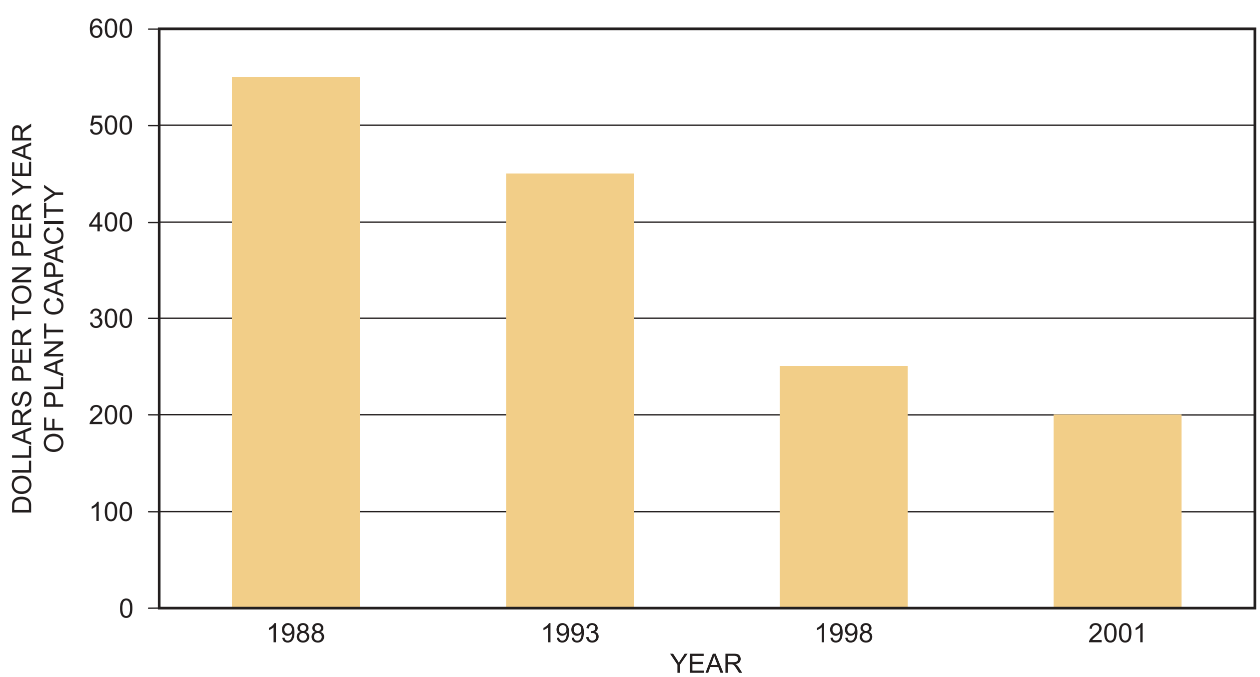
Figure L-4. Delivered Cost of LNG From a New Train Development

More than 90% of the world's current LNG liquefaction capacity is based on spiral wound heat exchanger technology developed by Air Products and Chemical Incorporated. Recently, however, new liquefaction process licensors have appeared, adding a level of competition within the licensing and contracting industry, helping to reduce costs even further. For example, the first train of LNG in Trinidad completed in 1999, uses the Phillips Optimized Cascade technology which has set new benchmarks for scale and unit cost for a new, single-train development. Other new entrants include Linde with their Mixed Fluid Cascade process, now being implemented in Snohvit project in Norway, and dual mixed refrigerant (DMR) Liquefin processes from Shell and IFP/Axens process. The entrance of competition into the heat transfer equipment combined with increased economies of scale has been the primary driver for unit cost reduction in the LNG industry.

Additional equipment competition could come into play as the LNG industry evaluates the potential benefits of using an all-electric drive option for the liquefaction plant. The Snohvit Project in Norway will be the first LNG project to employ large (60 megawatts) motor drives for the refrigeration unit compressors. This all-electric drive technology offers the potential for competition between suppliers of large electric motors, and between providers of large electric power plants, versus General Electric's virtual monopoly status for drivers in existing LNG plants.

Until recently, LNG developers have generally selected the largest liquefaction train size available; projects have gone ahead whenever a sufficiently large market, secured by long-term agreements, could be identified. As the feasible scale for new trains advances beyond 8 MTA to perhaps 10 MTA, developers will need to consider market needs in choosing the right scale for their projects. It may well be that the advantages of scale economies are sufficiently great to justify accepting a greater share of initial market and resource risk.

As shown in Figure L-5, liquefaction capital costs per ton of yearly capacity have significantly dropped in the last 15 years. Most of the reduction in cost is due to achieving economies of scale through larger train sizes. Due to existing infrastructure, expansions of existing operations have a significant cost advantage over new developments as they experience lower incremental costs when adding trains to existing facilities.



Source: Oil and Gas Journal, October 2, 2001.

Figure L-5. Reduction in Liquefaction Plant Cost Over Time

2. Shipping

Shipping has also experienced a dramatic reduction in cost over the last six years. As shown in Figure L-6, the cost of a standard 138,000 cubic meter vessel has fallen by approximately 40% since 1996. This reduction was primarily caused by increased competition in the shipbuilding industry, which in turn resulted from the entry of the Korean shipyards into the LNG vessel industry.

Even though Korean ship companies had built LNG carriers for Korean LNG supply contracts, before 1986 they had not won an international tender. Because the entry of Korea into the market also coincided with the devaluation of the Korean Won during the Asian financial crisis, their pricing became even more competitive. Hyundai Heavy Industries was the first Korean shipbuilder to win an international bid when they won the tender to build two vessels, each with a capacity of 137,300 cubic meters for the Nigerian Bonny Gas Transport. Two other Korean companies, Daewoo and Samsung, have also provided LNG vessels to other international companies.

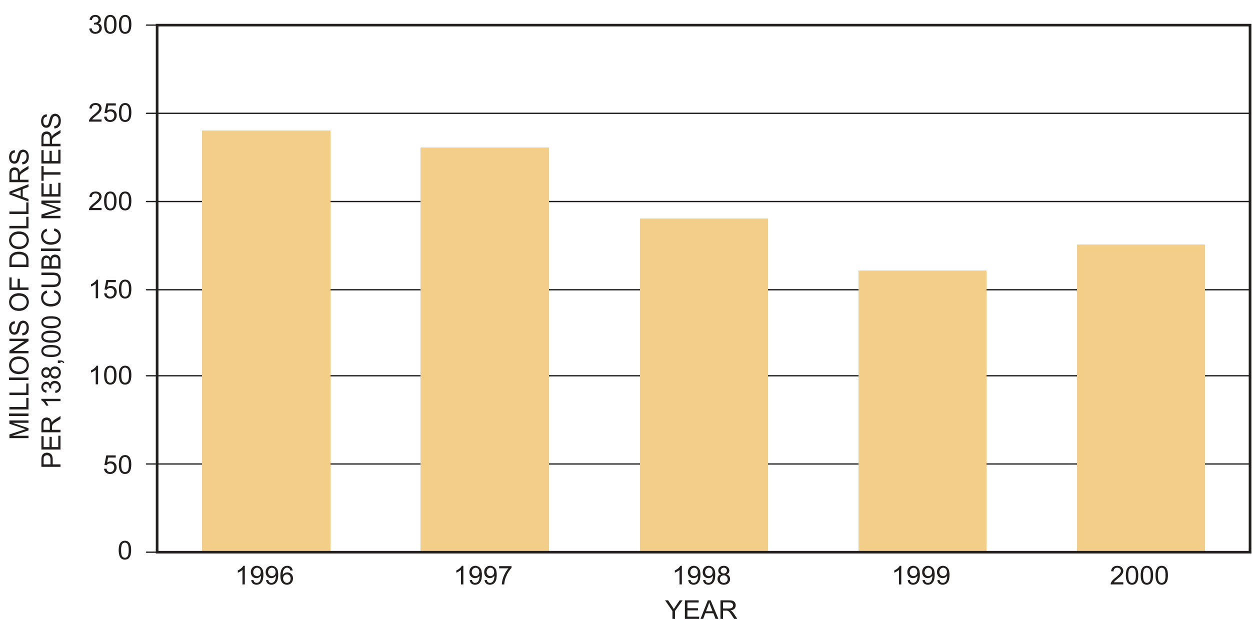
The Chinese are the most recent entry into the LNG ship building industry. They will be providing the vessels for the Guangdong project in China, and will be an additional competitor for new projects in the future.

Shipping will soon follow the trend of LNG liquefaction plants by achieving additional cost reductions through economies of scale. Already many companies have announced plans to built larger sized ships, increasing capacities to over 200,000 cubic meters.

3. LNG Cost Reduction Summary

Cost reductions in the liquefaction and transportation of LNG have made it possible for some previously uneconomic sources of supply to become competitive in the U.S. market. The recent increase in gas prices in the U.S. market has also made more supplies economically viable. Figure L-4 shows the effect of cost reductions in liquefaction and shipping for supplies 6,000 miles away from the United States. Even using the unescalated costs from the two charts above, a dramatic decrease in delivered price is evident.

LNG storage facilities are another key element of the value chain. These facilities, which require special insulated tanks, use a technology – high-nickel alloy steel tanks – that has changed little in the past 20 years. Cost reductions in storage have mainly been achieved



Note: Assumes 12,000 mile roundtrip voyage using 138,000 cubic meter vessel.
Source: Oil and Gas Journal, August 21, 2000.

Figure L-6. Reduction in LNG Ship Costs through improvements in schedule and scale. For example, the typical tank size has doubled to around 160,000 cubic meters during the past 20 years. Future reductions in storage costs may be possible by further increasing tank sizes, by innovations in construction methods, or by use of all-concrete tanks, which were first used successfully 20 years ago in Barcelona, Spain.[2]

The LNG industry will continue to seek ways to lower the cost of LNG through larger train and ship sizes. Although future gains are not likely to be as great as the ones already achieved, the next stage in the evolution of this technology promises to make LNG from even the most distant countries competitive with local gas supplies.

B. Growing U.S. Natural Gas Demand

The U.S. Energy Information Administration (EIA) predicts total U.S. energy consumption will increase from about 97 to about 130 quadrillion British thermal units (Btu) between 2001 and 2020, an average annual increase of 1.5%. This study projects natural gas consumption in the United States will increase by 7.2 TCF/year or 19.7 BCF/D during the same period. Demand for natural gas is projected to increase at an annual average rate of 1.2% between 2001 and 2025, primarily due to rapid growth in demand for electricity generation in the early part of the study period.

U.S. natural gas production has plateau since the late 1990s. This situation, combined with growing natural gas demand has lead to a tightening of the U.S. supply/demand balance, which in turn has lead to higher pricing levels. For example, early in 2003, the NYMEX strip price for gas delivered at the Henry Hub averaged over $5.00 per MMBtu.

C. Global LNG Demand

Until recently, the LNG industry has been separated into two major supply/demand regions, with only occasional marketplace interaction between the two. North African supplies have generally been directed to Europe, though some was also shipped to the U.S east coast. North Asian demand was met primarily by supplies from Southeast Asia and the Middle East, and to a limited extent, the U.S. (Alaska).

However, with the development of major Middle East LNG supplies that can economically go either east or west, the LNG industry is rapidly becoming a global market. African supplies are competing for both European and U.S. customers. Middle East supplies are competing for Asian and European as well as U.S. customers. And Southeast Asian supplies, though continuing to compete for north Asian customers, are also looking to expand their reach to the U.S. west coast.

This change in the market has important implications; it affects the security of supply of importers, and it also gives suppliers greater flexibility in their choice of markets. LNG supplies that were once thought to be too far away to be developed may now be developed economically. With more markets to choose from, LNG suppliers will naturally choose to go to those markets that offer the best combination of price, terms, market security and risk profile. Similarly, LNG buyers have more suppliers available to them so that they too can choose the best combination of price, terms, supply security, and risk profile. With increasingly global LNG trade, previously disconnected regional gas markets will become increasingly linked. If LNG grows to the point that it becomes a substantial component of each market's supply, natural gas could, ultimately, become a global fungible commodity, similar to crude oil today.

Table L-1 is a summary of historical LNG demand by importing country. Although Europe was the first destination for LNG, during the 1980-2000 period Asia (more specifically Japan, Korea, and Taiwan) has been the main LNG buyer. Demand in Asia was motivated mainly by the growing need for energy due to high rates of economic growth in the region. Lack of local sources of supply, limited access to pipeline gas and the desire for energy diversity also played a role. In this situation, the LNG "demand" was created and met with a long-term supply project.

By contrast, North America and Europe, which have very large natural gas markets, have not yet become large LNG importers mainly because of their greater access to pipeline gas supplies. LNG has penetrated in these markets only when local supplies are for some reason not competitive.

Import facilities in the United States were originally developed as part of a plan for moderating seasonal demand patterns. These facilities are unique compared

[2] Davies, N., "PC/PC Tanks – Is It Time For a Revival," *LNG Journal,* May/June 2002.

	1965	1970	1975	1980	1985	1990	1995	2000	1990-2000 Growth (%/year)
Europe									
U.K.	0.1	0.1	0.1	0.1		<0.1			
France	<0.1	0.1	0.3	0.2	0.8	0.9	0.8	1.0	
Spain		<0.1	0.1	0.2	0.2	0.4	0.7	0.7	
Italy			0.2	0.1	<0.1			0.5	
Belgium					0.2	0.4	0.5	0.4	
Turkey							0.1	0.4	
Greece								0.1	
Subtotal	**0.1**	**0.2**	**0.7**	**0.6**	**1.3**	**1.7**	**2.0**	**3.2**	**6.3%**
Asia									
Japan		0.1	0.6	2.2	3.6	4.6	5.6	7.3	
Korea						0.3	0.9	1.8	
Taiwan						0.1	0.3	0.6	
Subtotal		**0.1**	**0.6**	**2.2**	**3.6**	**5.0**	**6.8**	**9.7**	**6.8%**
Americas									
United States		<0.1	<0.1	0.2	0.1	0.2	0.1	0.6	
Puerto Rico								<0.1	
Subtotal		**<0.1**	**<0.1**	**0.2**	**0.1**	**0.2**	**0.1**	**0.7**	**10.6%**
World	**0.1**	**0.3**	**1.3**	**3.0**	**4.9**	**7.0**	**8.9**	**13.5**	**6.8%**

Note: Totals may not add due to rounding.
Sources: 2000 – DOE/EIA; 1965-1995 – Cedigaz.

Table L-1. Historical International LNG Demand (Billion Cubic Feet per Day)

to other nations in the world (see discussion of U.S. import facilities in Section V).

Historically, LNG has *not* been shipped to South America or to Asian countries other than Japan, Korea, and Taiwan, because of limited gas demand in those areas and ample supply from regional pipelines. This pattern is soon to change; China and Brazil have both announced potential LNG import projects.

Continuing growth in natural gas demand in the United States and Europe together with declining or flat indigenous production is creating opportunities for LNG supplies in these markets. With the resulting increases in natural gas prices in the U.S and U.K., and to some extent continental Europe, combined with the presence of existing deregulated, fully functioning infrastructure, and competitive "liquid" gas markets, LNG can now penetrate these markets in larger quantities. The only remaining barrier to increasing LNG imports is the construction of new import terminals.

Recent industry forecasts show significant increases in LNG demand, in the United States as well as in Europe and Asia. The traditional markets of Asia will continue to be the largest importers of LNG, but new entrants, such as India and China, will also be increasingly important buyers. Economic growth will be the main reason for continuing growth in demand from the traditional Asian buyers, Japan, Korea, and Taiwan, but policy choices with regard to fuel priorities (gas, coal, nuclear) will also play a role.

India and China are expected to experience significant overall energy demand growth. Their limited access to pipeline gas and alternate energy supplies, coupled with their need for supply diversity and security, is expected to result in their becoming significant importers of LNG. For India and China, and potentially other regional countries, uncertainty concerning LNG import demand is more related to commercial concerns than to doubts about the demand for the product. Regulation and credit worthiness are examples of commercial concerns.

Table L-2 shows a forecast of future worldwide LNG demand. Demand in the United States and Mexico is based on the work of this study. The forecast for the rest of the world is taken from Cambridge Energy Research Associates (CERA). While other studies show higher or lower values, most agree to the following:

- Worldwide LNG demand growth to 2020 will be substantially higher than worldwide gas demand growth (6-7%/year versus 2-3%/year) and substantially higher still than worldwide energy demand growth (6-7%/year versus 1.5-2.0%/year)

- U.S. LNG demand will accelerate rapidly, especially in the pre-2010 timeframe (the growth rate is higher in the 2002-2010 period than in the later years) because of a growing supply/demand gap that is a result of the inability of indigenous gas production to keep pace with gas demand growth.

- European LNG demand will accelerate rapidly, and will begin sooner, because of indigenous production limitations.

- Asian LNG demand will follow historical growth rates, which will be lower than those expected in Europe and North America.

	2005	2010	2000-2010 Growth (%/year)	2015	2020	2010-2020 Growth (%/year)	2000-2020 Growth (%/year)
Americas							
United States	2.3	5.6		7.1	9.9		
Mexico	0.0	1.7		1.8	1.8		
Carribean & Central America	0.2	0.4		0.4	0.5		
Subtotal	**2.3**	**7.7**	**27.1%**	**9.3**	**12.2**	**4.7%**	**15.4%**
Europe	**4.8**	**8.7**	**10.5%**	**10.2**	**11.7**	**3.0%**	**6.7%**
(Europe not available by country)							
Asia							
Japan	8.0	8.8		10.1	11.8		
Korea	2.7	3.3		4.3	4.8		
Taiwan	1.0	1.4		1.7	2.1		
China	0.2	0.7		0.9	1.6		
India	0.2	1.3		2.3	2.9		
Philippines	0.0	0.0		0.0	0.4		
Subtotal	**12.1**	**15.5**	**4.9%**	**19.3**	**23.6**	**4.3%**	**4.6%**
World	**19.2**	**31.9**	**9.0%**	**38.8**	**47.5**	**4.1%**	**6.5%**

Sources: U.S. and Mexico from NPC study; rest of world from CERA.

Table L-2. International LNG Demand Forecast (Billion Cubic Feet per Day)

D. Global LNG Import Terminals

Table L-3 lists the worldwide LNG import regasification terminals in service as of the end of 2002. Numerous additional terminals, as well as expansions of existing terminals have been announced and are in various stages of planning and development. Analysis of these terminal projects and forecasts of future worldwide terminal capacity are beyond the scope of this study (other than for the United States, which is provided in Section VI). However, it is the view of the authors that adequate terminal capacity will be developed worldwide to meet the demand forecast provided above. Figure L-7 illustrates the worldwide locations of existing and potential future LNG import regasification terminals.

E. Market Drivers

LNG is a capital-intensive industry. For investors to make the commitments necessary to finance these projects they need to be assured about the stability of the commercial structures and the economic return, taking into account the risk at each stage of the value chain. This consideration has become even more important as the size and capital intensity of LNG has increased over the years.

The projects in the LNG value chain are interdependent in that they share commercial, political, and operating risks. Among the key risks are the physical characteristics of the gas resource, reliability of and access to local infrastructure, capacity availability, the full utilization of all the facilities throughout the value chain, and the customer's ability to pay.

The LNG value chain is held together by the commercial structure. A commercial structure is the framework of fiscal regimes, laws, regulations, contracts, and financial obligations that governs the individual segments, as well as the links between them. This commercial structure must be flexible if it is to accommodate changes in the business environment. It must also be durable, and it must allocate risks and rewards fairly throughout the life of the project.

Historically, most LNG plant developments were supported in advance of construction by one or more long-term sales contracts with one or more buyers, who typically were high credit-rated electric utilities or gas distribution companies in the importing country. Such contracts were typically 20-25 years in duration, with limited volume flexibility, and with high take-or-pay provisions. Pricing was usually indexed to crude

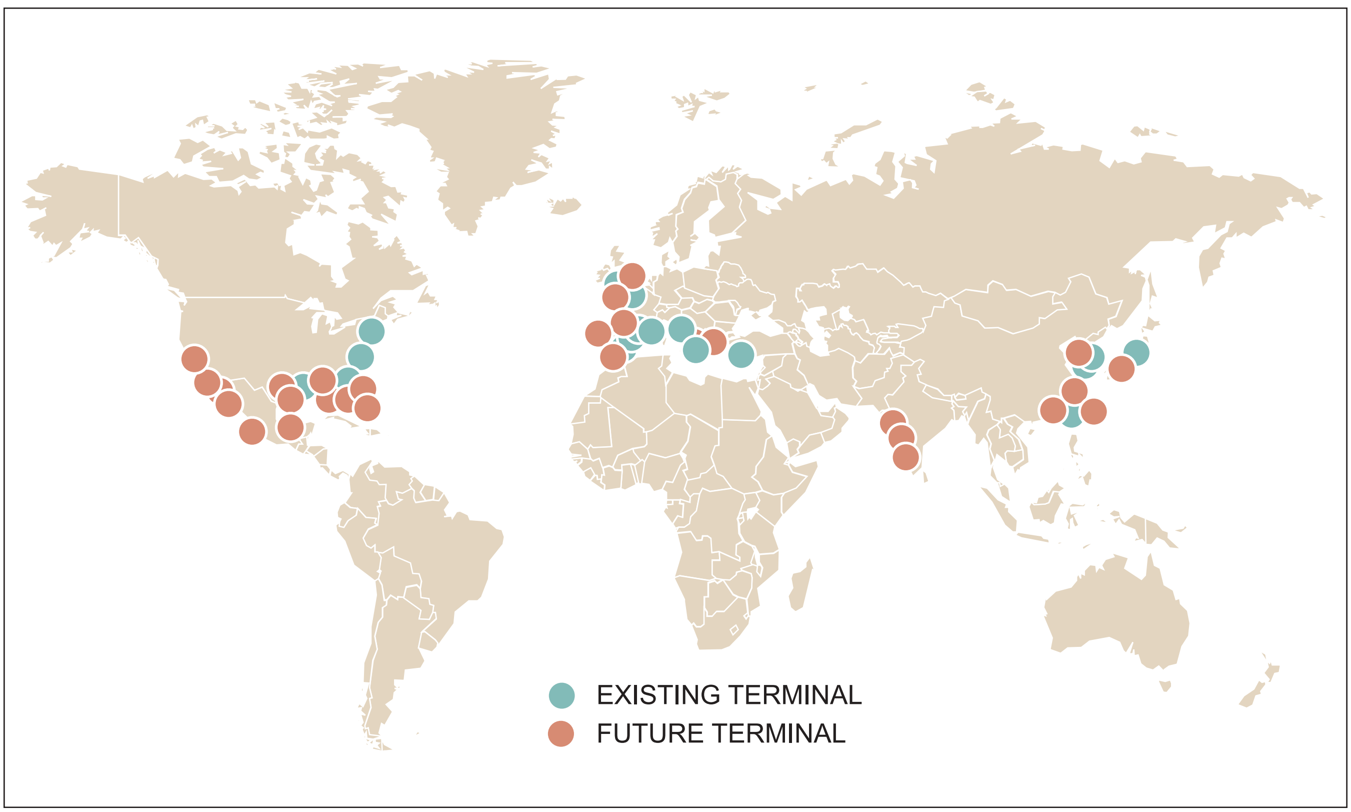


Figure L-7. LNG Import Regasification Terminal Locations

	Terminal	Storage (km³)*	Capacity (Mm³/d)*	Owner	Start	Primary Supply
N. America						
U.S.	Everett	155	8.1	Tractebel	1971	Algeria, Trinidad
	Cove Point	240	32.0	Dominion	1978	Norway
	Elba Island	189	13.0	El Paso	1978	Trinidad
	Lake Charles	286	19.8	Trunkline LNG	1982	Spot Cargoes
Subtotal		**870**	**72.9**			
Europe						
U.K.	Canvey Island	55	4.5	British Gas	1964	Closed in 1990
Spain	Barcelona	240	29.0	Enagas	1970	Libya/Algeria
	Huelva	160	6.3	Enagas	1988	Algeria
	Cartagena	55	3.6	Enagas	1989	Algeria
Italy	Panigaglia	100	11.0	SNAM	1971	Spot cargoes
France	Fos-sur-Mer	150	22.0	Gas de France	1972	Algeria
	Montoir-de-Bretagne	360	31.0	Gas de France	1980	Algeria
Belgium	Zeebrugge	261	17.8	Distrigas	1987	Algeria
Turkey	Marmara Ereglisi	255	13.0	Botas	1994	Algeria
Subtotal		**1,636**	**137.4**			
Asia						
Japan	Negishi	1,250	50.8	Tokyo Electric Tokyo Gas	1969	U.S./Brunei
	Senboku I	180	8.4	Osaka Gas	1972	Brunei
	Sodegaura	2,660	103.6	Tokyo Electric Tokyo Gas	1973	Brunei/UAE/ Malaysia/Australia
	Senboku II	1,405	43.8	Kansai Electric Osaka Gas	1977	Indonesia/Australia
	Tobata	480	24.0	Kyushu Electric Nippon Steel	1977	Indonesia/Australia
	Chita I	300	27.0	Chubu Electric Toho Gas	1977	Indonesia
	Himeji I	520	31.6	Kansai Electric	1979	Indonesia/Australia
	Chita II	640	42.9	Chubu Electric Toho Gas	1983	Indonesia/Australia
	Higashi-Nilgata	720	31.4	Tohoku Electric	1983	Indonesia
	Himeji II	560	14.8	Osaka Gas	1984	Indonesia/Australia
	Higashi-Ohgishima	540	62.9	Tokyo Electric	1984	Malaysia/Indonesia
	Futtsu	610	69.3	Tokyo Electric	1985	Malaysia/Australia
	Yokkaichi	320	29.2	Chubu Electric	1987	Australia/Indonesia
	Yanai	480	7.5	Chugoku Elect.	1990	Australia/Indonesia
	Shin-Otta	320	17.2	Kyushu Electric	1990	Australia/Indonesia
	Yokkaichi	160	2.4	Toho Gas	1991	Indonesia
	Fukuoka	70	1.7	Saibu Gas	1993	Malaysia
	Hatsukaichi	85	1.3	Hiroshima Gas	1996	Indonesia
	Sodeshi	83	2.3	Shizuoka Gas	1996	Malaysia
	Kagoshima	36	0.5	Nippon Gas	1996	Indonesia
	Shin-Minato	80	1.1	Sendai	1997	Malaysia
	Kawagoe	480	19.4	Chubu Electric	1977	Qatar
	Ohgishima I	200	10.7	Tokyo Gas	1998	Qatar
Korea	Pyeong Taek	1,000	60.0	Korea Gas	1986	Indonesia
	Incheon	600	48.0	Korea Gas	1996	Indonesia/Malaysia
Taiwan	Yung-An	300	22.0	CPC	1990	Indonesia
Subtotal		**14,079**	**734**			
World		**16,585**	**944.3**			

* m^3 = cubic meters.
Source: CEDIGAZ.

Table L-3. Regasification Terminals in the World – 2002 oil at levels competitive with alternative liquid fuels at the buyer's location.

These arrangements met important needs for both the seller and buyer. The seller was able to obtain financing supported by the strong contract, with its certain volumes and cash flow. The buyer was assured dedicated security of supply at a price that was competitive with other fuels. This model has served well during the formative and development years of the LNG industry.

Even within this contractual structure, some spot or short-term sales have been made; in most cases, however, these sales were based on incremental liquefaction plant and ship capacity above that required by existing long-term contracts. It has not been industry practice to develop liquefaction plants on a speculative basis without long-term contracts to underpin a large portion of the plant's capacity.

In the past few years, a number of countries have been in the process of implementing energy market "liberalization." Electric utilities and gas distribution companies in these countries have found themselves in a new environment, with decreased ability to pass through fuel costs, and greater uncertainty about their role in meeting future energy demand. Consequently, buyers are looking for additional flexibility in new contracts and are increasingly asking for contracts with shorter terms. Buyers are also soliciting individual cargo spot sales and/or short-term sales to gain greater control in balancing their individual supply and demand portfolios over the short term. As these market changes occur, the risk/reward picture also changes, with sellers taking on more volume uncertainty related to fluctuations in local energy demand. Nevertheless, developing new LNG capacity will continue to require capital investments in the 2.0 to 5.0 billion dollar range for capacities of up to 1.0 BCF/D. Moreover, the investors will continue to require a stable commercial structure and economic returns commensurate with risks.

Historically, LNG markets were created at the same time as LNG supply projects. In the U.S. and U.K., and to some extent in continental Europe, because of the high degree of interconnection of gas pipelines and demand centers, a different kind of market has been created. This market is large, "liquid" and highly competitive. It is also able to accommodate large volumes and can provide an assured outlet for sellers at prevailing market prices with little volume risk. Buyers can also obtain the variable volumes they need, within reason, at prevailing market prices. LNG suppliers are now looking to locate their own LNG import regasification terminals at coastal locations reasonably close to large gas pipeline connections, especially along the gulf, east and west coasts of the U.S., and on the east and west coasts of the U.K. In these markets, LNG investors will need to form views with regard to overall market demand and future hub pricing in order to determine whether they can achieve the stable commercial structure and economic return they need.

While the "liquid" market characteristics for the U.S. and U.K. are significantly different from the traditional outlets for LNG, the development of the LNG chain will still require the security of long-term supply contracts. This is driven by the fact that most of the gas reserves available for potential LNG development are located on foreign soil and are under the control of and often owned by foreign governments. These governments typically will not have the in-house finances to develop a LNG project and will in turn rely on project financing. Lenders will continue to seek long-term commitments as a condition for financing these projects.

A further requirement will be the absolute guarantee of access to the marketplace. For LNG projects, this means access to LNG regasification import capacity without the uncertainty created by mandatory third party access requirements.

F. Competitive Market Place

The LNG industry is evolving into a global market. Most supply projects are able to reach two or more demand regions, each with multiple buying countries. Moreover, most buyers are able to receive competitive offers from a large numbers of suppliers. In the long run, the LNG market has the potential to become an interconnected world market. Several factors will determine how LNG markets will develop.

The main factor that will determine future trade flows is price. Suppliers with a choice of market outlets will naturally sell to the one with the higher price. As an example, West African, northern South American, and Middle East suppliers can sell to either the European or U.S. markets. The gas price in Europe relative to the United States, after allowing for transportation cost differences, will be a major determinant of the direction of LNG trade. To the extent LNG supply represents the marginal supply source, this market will serve to equalize the price of gas in different regions. Local gas prices will no longer be determined solely by the local or regional supply/demand balance.

Considering the large investments and long-term nature of the LNG value chain, creation of a viable worldwide competitive market in LNG will depend on achieving commercial stability and certainty of outlet. A fundamental requirement for commercial stability is general acceptance of the sanctity of the contracts at every stage in the value chain. Contract sanctity is most often challenged when markets become unbalanced – either because of too much or too little committed supply – a situation that often arises because of market distortions caused by over-regulation.

Avoidance of regulatory distortions involves a number of considerations, including:

- Commodity prices should be transparent and determined in a competitive market where all suppliers are allowed to compete on equal footing. Transparency and market-based pricing will insure that buyers and sellers are able to make their decisions considering all relevant market factors, without disadvantage. The United States has a significant advantage compared to some other LNG importing countries in this regard. Subsidies, import restrictions, and other sources of market distortion have the effect of raising the cost of supply.

- The legal, fiscal, and regulatory frameworks must be stable and be perceived as such. Nothing worries investors more than the potential changes in the fiscal and regulatory framework. Most investors view the United States as having a stable legal and fiscal framework; that is not true for many other countries that import LNG. The regulatory framework in governing the U.S. gas market has changed significantly over the past 2-3 decades. Some participants have benefited from these changes; others have not. The current U.S. gas market regulatory framework is generally thought to be working well, and care must be taken when considering any changes so as to avoid any unintended consequences.

- Finally, although not as much a problem in the U.S. as in other countries, there are other important considerations. For example, laws, regulations, and dispute resolution should be administered in an equitable and non-discriminatory manner, and there should be no artificial obstacles to building, owning, operating, and competing for gas infrastructure. Regulatory intervention should be limited to preventing predatory, monopolistic, or anti-competitive behavior.

Future supplies of U.S. base-load LNG import volumes will probably be tied to dedicated long-term supply agreements, with dedicated infrastructure. However, it is expected that the predominant form of LNG importation will be through regasification terminals, which will be sited so as to connect to high volume pipelines. Some terminals will be owned and operated by LNG suppliers; others will be owned and operated by companies providing the service to suppliers. The local supply/demand balance will serve to attract LNG trade flows as needed to fill demand. Prices, as in all competitive markets, will act either to attract or discourage LNG imports as required by market conditions.

IV. Competitive LNG Supplies for North America

A. Global LNG Supply

The first commercial production of LNG occurred in September 1964 in Algeria, which supplied nominal amounts of about 0.10 to 0.15 BCF/D to the U.K. and France through the remainder of the 1960s. Subsequently, Algerian production has grown to well over 2 BCF/D, mostly for export to Europe. Libya joined Algeria as a supplier beginning in 1970 and reached maximum production of 0.35 BCF/D in 1977, all for delivery to Europe. Production there has subsequently slipped to less than 0.1 BCF/D. Small production capacity was developed in the U.S. (Alaska) in 1969.

Beginning in the 1970s, significant production capacity in Brunei and Indonesia, and later in Malaysia and Australia, was brought online to supply Japan, and subsequently, Korea, and Taiwan. By 2000, production rates from these four Asia Pacific supply countries exceeded 7 BCF/D, with the vast majority going to Japan, Korea and Taiwan. This development constitutes the core of today's global LNG industry.

Supply of LNG from the Middle East began first from the United Arab Emirates in 1977; subsequently, production capacity was developed in Qatar (1997) and in Oman (2000). LNG from the Middle East has been exported mainly to Japan and Korea, though smaller quantities have gone to Europe and the United States.

Today, however, these suppliers are increasingly looking to markets in the West for export via the Suez Canal.

Recently, major new LNG supply capacity has also been developed in the Atlantic Basin in both Nigeria and Trinidad/Tobago. Nigerian LNG projects have been largely dedicated to the Southern European markets; the projects in Trinidad/Tobago are supplying the U.S., Spanish, and Caribbean markets.

Table L-4 is a summary of historical LNG supply.

1. Supply Sources

The projects listed in Table L-5 were identified as possible future sources of natural gas for the North American market. As shown in the table, this analysis is limited to future incremental supplies to the United States from new projects that have indicated that the United States is a potential destination for a portion of the capacity. Existing trains were not included since those volumes are already committed to other buyers under long-term contracts.

	1965	1970	1975	1980	1985	1990	1995	2000	1990-2000 Growth (%/year)
Africa									
Algeria	0.1	0.1	0.4	0.7	1.2	1.8	1.8	2.6	
Libya		<0.1	0.3	0.2	0.1	0.1	0.1	0.1	
Nigeria								0.4	
Subtotal	**0.1**	**0.1**	**0.7**	**0.8**	**1.3**	**2.0**	**1.9**	**3.1**	**4.8%**
Americas									
United States		0.1	0.1	0.1	0.1	0.1	0.2	0.2	
Trinidad								0.4	
Subtotal		**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.6**	**15.7%**
Asia Pacific									
Brunei			0.5	0.7	0.7	0.7	0.8	0.9	
Indonesia				1.1	1.9	2.7	3.2	3.6	
Malaysia					0.6	0.8	1.3	2.0	
Australia						0.4	1.0	1.0	
Subtotal			**0.5**	**1.8**	**3.2**	**4.6**	**6.2**	**7.5**	**5.0%**
Middle East									
United Arab Emirates				0.3	0.3	0.3	0.7	0.7	
Qatar								1.4	
Oman								0.3	
Subtotal				**0.3**	**0.3**	**0.3**	**0.7**	**2.4**	**22.5%**
World	**0.1**	**0.3**	**1.3**	**3.0**	**4.9**	**7.0**	**8.9**	**13.5**	**6.8%**

Note: Totals may not add due to rounding.
Sources: 2000 data – DOE/EIA; 1965-1995 data – Cedigaz.

Table L-4. Historical International LNG Supply (Billion Cubic Feet per Day)

Country	Project	Start Date	Train Size	Train Size	Minimum Estimated FOB Cost	Maximum Estimated FOB Cost	Shipping Cost GOM	Minimum Landed Cost	Maximum Landed Cost
			MTA	BCF/D	$/MMCF	$/MMCF	$/MMCF	$/MMCF	$/MMCF
ATLANTIC BASIN SUPPLIES									
Angola	Angola LNG	2008	4.0	0.52	1.50	2.00	0.98	2.48	2.98
Equatorial Guinea	Alba	2008	3.6	0.47	1.00	1.50	0.92	1.92	2.42
Nigeria	NLNG Plus	2006	8.1	1.05	1.00	1.50	0.92	1.92	2.42
Nigeria	Brass River	2008	5.0	0.65	1.50	2.00	0.92	2.42	2.92
Nigeria	Nnwa Doro	2009	4.8	0.62	2.50	3.00	0.92	3.42	3.92
Algeria	Gassi Touil	2008	3.3	0.43	2.50	3.00	0.70	3.20	3.70
Egypt	ELNG I	2005	3.6	0.47	1.00	1.50	0.89	1.89	2.39
Egypt	ELNG II	2006	3.6	0.47	1.00	1.50	0.89	1.89	2.39
Norway	Snøhvit	2006	4.2	0.55	3.00	3.00	0.84	3.84	3.84
Trinidad	ALNG II	2002	3.3	0.43	1.00	1.50	0.44	1.44	1.94
Trinidad	ALNG III	2003	3.3	0.43	1.50	2.00	0.44	1.94	2.44
Venezuela	Mariscal Sucre	2009	4.7	0.61	1.50	2.00	0.41	1.91	2.41
Subtotal			**51.5**	**6.70**					
MIDDLE EASTERN SUPPLIES									
Qatar	Qatargas 4	2005	4.8	0.62	1.00	1.50	1.53	2.53	3.03
Qatar	Qatargas 5	2007	7.0	0.91	1.00	1.50	1.53	2.53	3.03
Qatar	Qatargas 6	2009	7.0	0.91	1.00	1.50	1.53	2.53	3.03
Iran	Iran LNG	2010	8.0	1.04	1.00	1.50	1.61	2.61	3.11
Oman	Oman Expansion	2008	3.3	0.43	1.00	1.50	1.48	2.48	2.98
Yemen	Yemen LNG	2010	3.1	0.40	1.50	2.00	1.34	2.84	3.34
Subtotal			**33.2**	**4.32**					
ASIA PACIFIC SUPPLIES							**Shipping Cost to WC US**		
Australia	NWS Expansion I	2004	4.2	0.55	1.00	1.50	1.18	2.18	2.68
Australia	NWS Expansion II	2006	4.2	0.55	1.00	1.50	1.18	2.18	2.68
Australia	Gorgon Area	2010	5.0	0.65	2.00	2.50	1.18	3.18	3.68
Australia	Greater Surise	2010	4.8	0.62	2.00	2.50	1.18	3.18	3.68
Australia	Bayu Undan	2006	4.8	0.62	2.00	2.50	1.18	3.18	3.68
Indonesia	Bontang I	2010	3.5	0.46	1.00	1.50	0.97	1.97	2.47
Indonesia	Tangguh	2007	7.0	0.91	1.50	2.00	0.97	2.47	2.97
Malaysia	MLNG Tiga I	2003	3.4	0.44	2.00	2.50	0.99	2.99	3.49
Malaysia	MLNG Tiga II	2004	3.4	0.44	2.00	2.50	0.99	2.99	3.49
Peru	Camisea	2007	4.5	0.59	2.50	3.00	0.59	3.09	3.59
Bolivia	Pacifico LNG	2010	6.6	0.86	2.00	2.50	0.66	2.66	3.16
Russia	Sakhalin 2	2007	9.6	1.25	2.00	2.50	0.65	2.65	3.15
Subtotal			**61.0**	**7.93**					
Total Supplies			**145.7**	**18.94**					

Table L-5. New Potential LNG Supplies

2. Assumptions and Breakeven Cost Calculations

Estimates of reserves, the corresponding train sizes, and the FOB cost of the LNG are based on the Wood Mackenzie country-by-country evaluation performed for the NPC. Details about assumptions are outlined in the individual country summaries that can be found in Appendix C, "Individual Country Summaries Prepared by Wood Mackenzie."

3. Supply Volumes to North America

The projected worldwide supply of LNG suggests that sufficient volumes will be available to meet estimated U.S. demand. However, if the global supply of LNG is constrained, the United States must be able to attract volumes away from Europe, which is the nearest alternative destination for most LNG supply sources.

The Supply versus Time graph shown in Figure L-8 uses the projected startup dates from the Wood Mackenzie study. The projected LNG demand curves are also shown on the same graph to demonstrate that demand in North America can be met from LNG projects that are being developed for export or proposed for development.

4. U.S. Natural Gas Imports

Natural gas production in the United States has fallen short of consumption since about 1985, as shown in Figure L-9. Consumption of gas in 2002 was 22 TCF; it is projected to grow at a 1.8% annual rate to an estimated 25 TCF by 2010 and to more than 28 TCF by 2020. Existing U.S. natural gas production is in decline, and replacement of domestic production from new fields and discoveries have not been sufficient to keep up with demand. Net gas imports were about 3.6 TCF in 2001 and are projected to increase by 65% over the next decade.

Figure L-9 also shows that Canada has been the main source of imported gas to the United States. However, projections by the NPC and Canadian National Energy Board indicate that it will be increasingly difficult for Canada to sustain and replace Canadian natural gas production. The difference between Canadian and domestic supply and U.S. demand has been made up mostly by imports of LNG. Historically, LNG has made a minimal contribution to U.S. supply. That is about to change. During 2001, LNG imports amounted to only 0.2 TCF of gas, but by 2010 LNG imports are forecast to

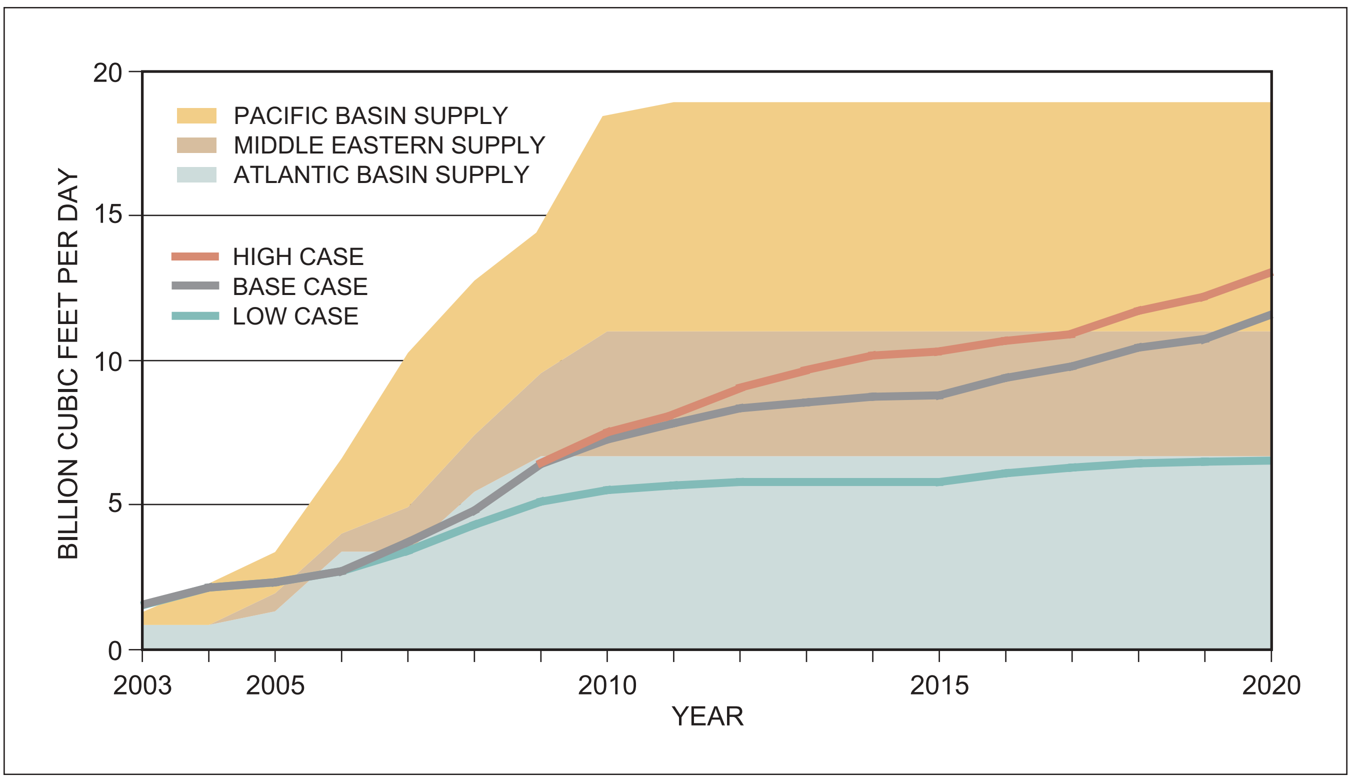
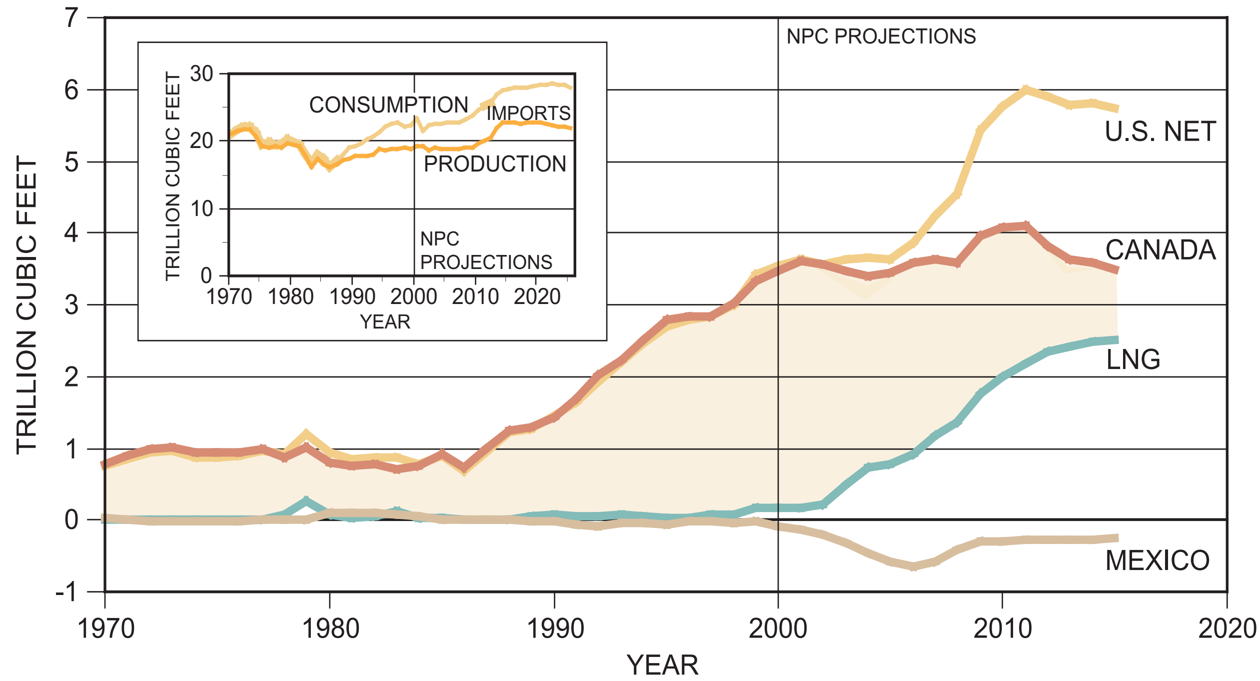


Figure L-8. LNG Supply Growth and North American Demand



Source: Energy Information Administration.

Figure L-9. U.S. Net Imports of Natural Gas

increase to 2 TCF. This estimate may be conservative. Any shortfall in projected U.S. domestic production from yet undiscovered and undeveloped fields or any decline in Canadian imports will further increase the opportunity for LNG. The United States can safeguard its natural gas supply position by ensuring that sufficient regasification terminals are planned and that permits are issued in a timely manner so that the U.S. can compete with European and Asian markets for new LNG supplies. As a target, the United States must attract 2 TCF of gas per year, which amounts to 5.5 BCF/D or 42 metric tons per year of liquefaction capacity.

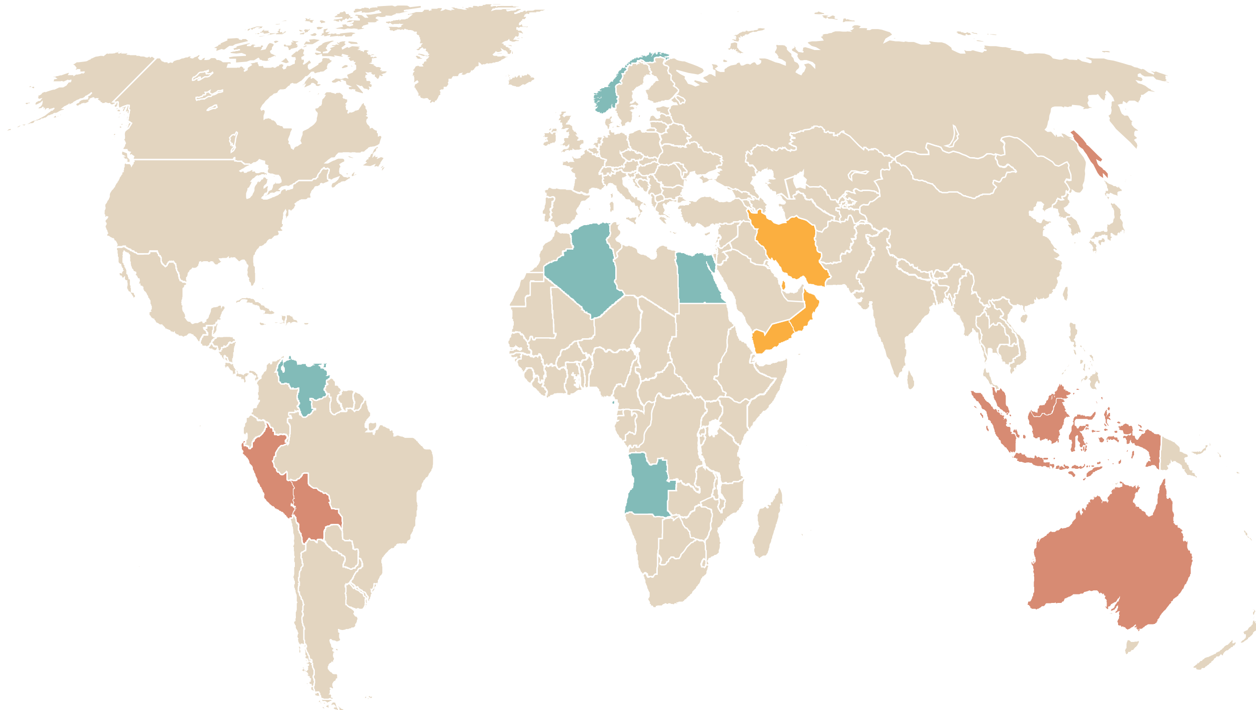
The outlook for world natural gas supply that could economically reach the United States is promising. As shown in Figure L-10, announced gas supplies are estimated at 112 TCF from the Pacific, 100 TCF from the Atlantic, and 54 TCF from the Middle East, for a total of 266 TCF. As technological improvements and transportation efficiencies achieve even greater economies of scale, even more natural gas resources are expected to become available.

B. Liquefaction

1. Existing, Under Construction, and Proposed Capacity

Worldwide liquefaction capacity that either already exists, or capacity that is under construction, is summarized in Table L-6. There is estimated to be about 129 MTA of existing LNG liquefaction capacity that could serve U.S. markets by the end of 2002 and an additional 55 MTA that is under construction. In all, that adds up to about 184 MTA. Table L-7 is the same as Table L-6 except the values are given in billion cubic feet per day. Increased world energy demand and confidence in sustained higher energy prices has resulted in many announced LNG plant expansions and proposals for new projects. By 2010, worldwide capacity has the potential to grow by an additional 114 MTA if all newly announced expansions and proposed projects are realized. This would bring existing, under construction, and proposed new capacity to about 298 MTA by 2010, as shown in Figure L-11.

These liquefaction capacities are equivalent to an existing 2002 natural gas supply of 16.7 BCF/D, with an



PACIFIC:	
Australia	36
Bolivia	13
Indonesia	32
Malaysia	7
Peru	11
Russia	13
Subtotal	112

MIDDLE EAST:	
Qatar	15
Iran	10
Oman	10
Yemen	19
Subtotal	54

ATLANTIC:	
Angola	10
Nigeria	30
Norway	7
Eq.Guinea	4
Trinidad	23
Algeria	5
Egypt	10
Venezuela	11
Subtotal	100

TOTAL RESOURCES 266

Figure L-10. Potential Gas Supplies for U.S. LNG Import (Trillion Cubic Feet)

additional 7.2 BCF/D under construction. Almost all this supply is committed to existing buyers. Announced and proposed new projects would add another 15.0 BCF/D by 2010, with approximately 5 BCF/D from each of the supply areas, the Atlantic Basin, the Middle East, and Asia Pacific. This new capacity is the supply that the United States must compete for if we are going to succeed in capturing an estimated 5.5 BCF/D supply over the next 10 to 20 years. The announced and proposed new supply of 15.0 BCF/D is an unrisked number; many of these projects may not be realized. Timely terminal access and sustained gas prices are key factors that will influence project developers, host governments, national oil companies and international lenders.

Beyond 2010, industry forecasts suggest that further expansion of projects by that date and addition of

MTA	2002 Existing	2002 Under Construction	2002 Committed	2010 New Proposed	2010 Potential
Atlantic					
Algeria	13.4			3.3	16.7
Libya	1.3			0.0	1.3
Nigeria	9.0			17.9	26.9
Egypt		7.2		0.0	7.2
Norway		4.2		0.0	4.2
Trinidad	3.3	6.6		0.0	9.9
Angola				4.0	4.0
Equatorial Guinea				3.6	3.6
Venezuela				4.7	4.7
Subtotal	27.0	18.0	**45.0**	33.5	**78.5**
Middle East					
UAE	5.5				5.5
Oman	3.3			3.3	6.6
Qatar	13.2	9.4		18.8	41.4
Iran				8.0	8.0
Yeman				3.1	3.1
Subtotal	22.0	9.4	**31.4**	33.2	**64.6**
Asia Pacific					
US	1.3			0.0	1.3
Brunei	6.6			0.0	6.6
Indonesia	27.6			10.5	38.1
Malaysia	22.7	6.8		0.0	29.5
Australia	7.5	4.2		18.8	30.5
Peru				4.5	4.5
Bolivia				6.6	6.6
Russia (Sakhalin)				9.6	9.6
Subtotal	65.7	11.0	**76.7**	50.0	**126.7**
Total MTA	**114.7**	**38.4**	**153.1**	**116.7**	**269.8**

Table L-6. LNG Plant Capacity (Million Tonnes per Annum)

other new projects could add incremental new capacity of 80 MTA, or approximately 10 BCF/D by 2020. However, a portion of this volume may be needed to replace existing LNG production.

The Atlantic Basin and the Middle East are well-positioned to support existing LNG liquefaction plant expansions as well as new developments. This is because access to secure capacity at existing and proposed U.S. receiving terminals has been enabled by recent changes in U.S. legislation. Sustained energy prices above the $3.50 per MMBtu will build confidence for governments and investors alike for investing in LNG projects.

Large quantities of stranded gas are known to exist in remote locations. Energy conservation and clean air regulations have caused national and international oil companies to implement rigorous programs to reduce or stop gas flaring associated with oil production and invest in gas industry ventures. Previously discovered non-associated gas resources are also beginning to appear to be more promising as uncertainties about commercial viability, terminal access, and transportation cost are being addressed.

2. Feedstock and Liquefaction Costs

Feedstock gas is the term used for natural gas produced from the ground and liquefied. The supply cost for feedstock gas varies widely. The cost on the low end is about $0.30/MMBtu, which is the cost for gathering and transporting (by pipeline) the waste gas associated with oil production. On the high end, the cost can be

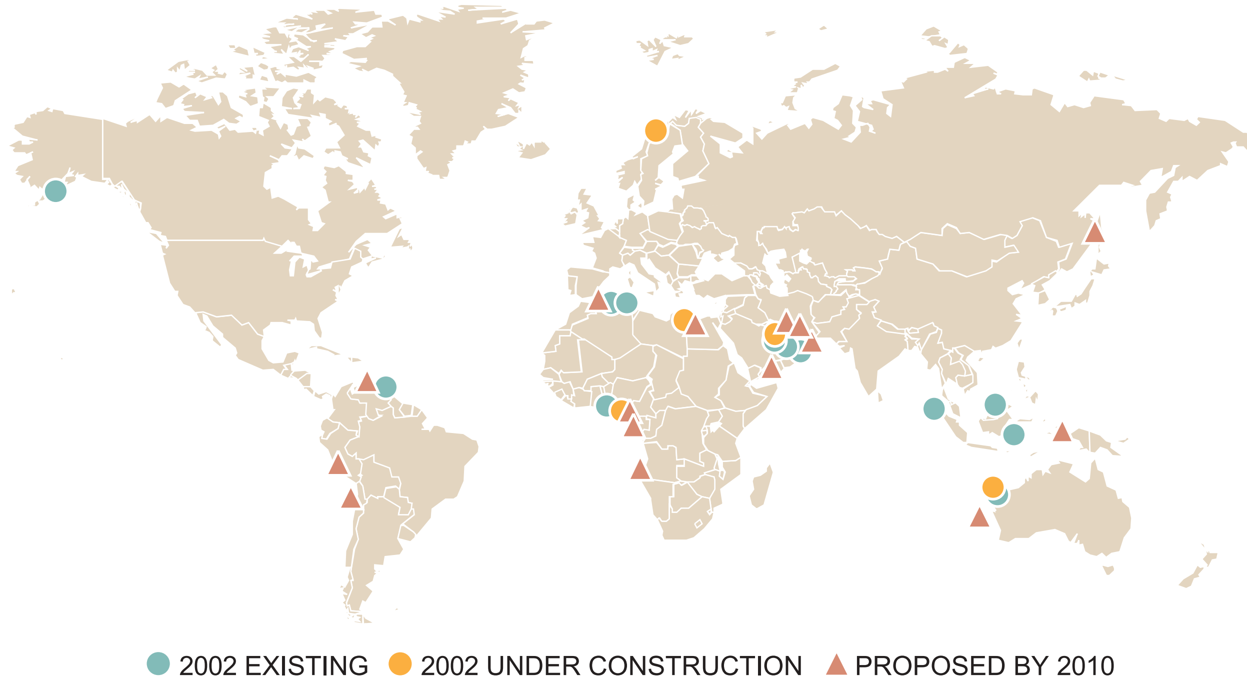
BCF/D	2002 Existing	2002 Under Construction	2002 Committed	2010 New Proposed	2010 Potential
Atlantic					
Algeria	1.7			0.4	2.2
Libya	0.2				0.2
Nigeria	1.2	0.0		2.3	3.5
Egypt		0.9			0.9
Norway		0.5			0.5
Trinidad	0.4				0.4
Angola				0.5	0.5
Equatorial Guinea				0.5	0.5
Venezuela				0.6	0.6
Subtotal	3.5	1.5	**5.0**	4.4	**9.3**
Middle East					
UAE	0.7				0.7
Oman	0.4			0.4	0.9
Qatar	1.7	1.2		2.4	5.4
Iran				1.0	1.0
Yeman				0.4	0.4
Subtotal	2.9	1.2	**4.1**	4.3	**8.4**
Asia Pacific					
US	0.2				0.2
Brunei	0.9				0.9
Indonesia	3.6			1.4	5.0
Malaysia	3.0				3.0
Australia	1.0	0.5		2.4	4.0
Peru				0.6	0.6
Bolivia				0.9	0.9
Russia (Sakhalin)				1.2	1.2
Subtotal	8.5	0.546	**9.1**	6.5	**15.6**
Total BCF/D	**14.9**	**3.3**	**18.2**	**15.2**	**33.3**

Conversion: 1 MTA = 0.13 BCF/D

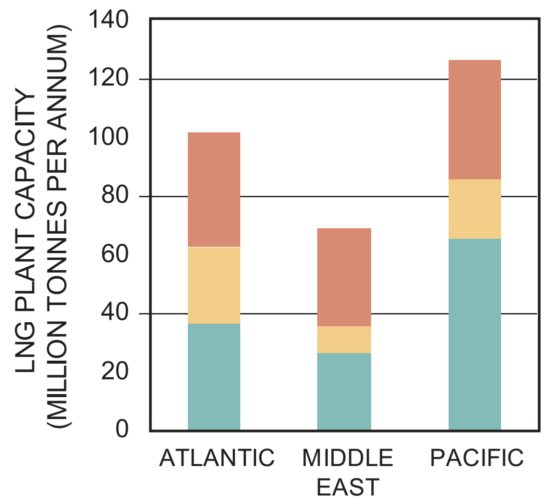
Table L-7. LNG Plant Capacity (Billion Cubic Feet per Day)

as high as $1.50/MMBtu for offshore development of gas in deepwater, both associated and non-associated with oil production. The unit cost of feedstock gas depends on the size and location of hydrocarbon reserves and the reservoir development plan constructed for extracting, processing, and delivering the gas to a liquefaction facility. Key cost factors include the quantity of proven gas reserves and estimates of unproven gas resources, the composition of the gas and any contaminants in it, reservoir pressure, and the deliverability or production rate of gas from the reservoir. For associated gas, key factors also include the quantity of oil reserves and resources, the oil production rate, the associated gas-to-oil yield, and the reservoir production decline rate. The physical location of the oil or gas field, whether it is accessible or remote, onshore or offshore, in shallow or deep water, will also affect development costs and pipeline transportation costs.

Liquefaction costs range from a low of about $0.70/MMBtu for investment in an expansion LNG processing plant to as high as $1.50/MMBtu for grass root construction of a new LNG plant in a remote and/or offshore area. The unit cost per MBtu for liquefaction depends on the location and capacity of the LNG plant, the facilities needed to remove any condensate, the liquid content and contaminants from the feedstock gas, the location and capacity of LNG storage, the existence or need to construct a suitable



	GLOBAL POTENTIAL			
MTA	**Atlantic**	**Middle East**	**Pacific**	**Total**
Proposed by 2010	39.4	33.2	41.0	113.6
2002 Under Construction	26.1	9.4	20.0	55.5
2002 Existing	36.6	26.4	65.7	128.7
Total	102.1	69.0	126.7	297.8
BCF/D	**Atlantic**	**Middle East**	**Pacific**	**Total**
Proposed by 2010	5.1	4.3	5.3	14.8
2002 Under Construction	3.4	1.2	2.6	7.2
2002 Existing	4.8	3.4	8.5	16.7
Total	13.3	9.0	16.5	38.7



Note: New LNG terminals will primarily target the new LNG projects proposed by 2010.

Figure L-11. Existing 2002, Under Construction, and Proposed LNG Liquefaction Capacity

deepwater port for LNG vessels, and economies of scale achieved by the LNG plant. The cost to purchase LNG supply at the tailgate of an LNG liquefaction plant inclusive of feedstock cost (referred to as FOB cost) may range as low as $1.00/MMBtu to as high as $3.00/MMBtu. Table L-9 later in this section shows estimates of worldwide FOB costs in 2010 for LNG supplies from possible LNG suppliers.

C. Shipping

The Atlantic Basin LNG trade between North African and West African supply sources and the European-Mediterranean market is well established. Long term and spot cargo sales to the United States have also occurred as shown in Figure L-12. Notable, however, is the advent of spot sales trade from the UAE beginning in 1996 and from Qatar in 1999, indi-

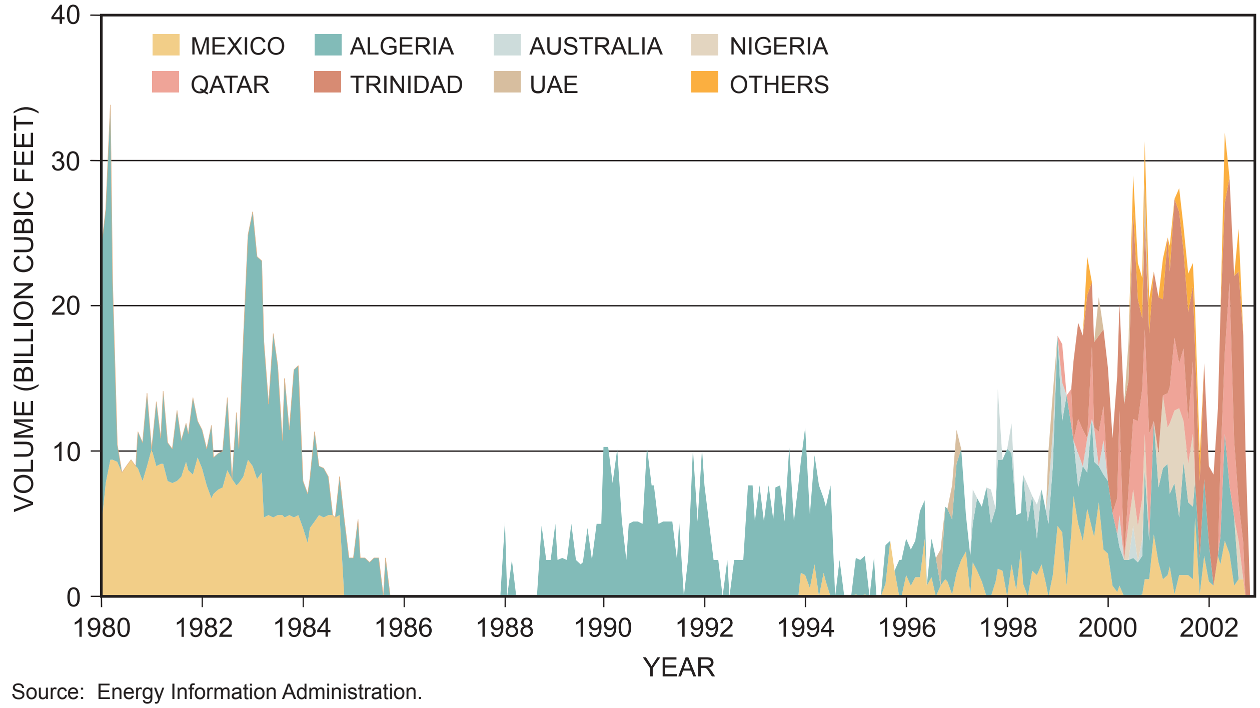


Figure L-12. U.S. Historical Monthly Gas Imports

cating that incremental sales to the U.S. from the Middle East are commercially viable. Some countries have negotiated special arrangements for passage through the Suez Canal, which has made trade with the European-Mediterranean and the U.S. possible. A major concern restricting trade with the United States is the cost of transportation over the longer distance.

As of September 2003, the world LNG carrier fleet comprises 140 vessels in the 120,000 to 147,000 cubic meter class, as illustrated in Figure L-13. Historically, the LNG trade has depended on point-to-point sales contracts and dedicated LNG shipping fleets. In recent years, there has been a slight surplus of shipping capacity. As indicated in Figure L-12, based on current orders for ship construction, an excess supply for shipping capacity is forecast to remain through 2007. After that time, the demand for new ships will continue to grow because of the need for new vessels to meet the growing demand for LNG and to replace older vessels that will be retired from service.

The shipping industry is currently constructing LNG ships as large as 147,000 cubic meters (gross capacity). About half the existing LNG terminals around the world are now able to accept these large ships. For ships above this size, however, there are few accessible ports. Proposed LNG ventures are considering the use of ultra large LNG ships, on the order of 200,000 to 250,000 cubic meters. The economies of scale achieved by using these large ships would greatly enhance transportation economics, and the potential benefit from using ultra large LNG ships is more pronounced for longer distance trades. Because of limitations on length, breadth, draft, or displacement (physical impact including windage on terminal infrastructure), there are currently no existing LNG terminals which would be able to accommodate such large ships. Investment in ultra-large LNG ships would thus need to be accompanied by a significant investment in new port and terminal capabilities together with increased LNG storage capabilities at both the loading and discharge ends of the trade.

Over the past few years, a few major LNG players have acquired uncommitted LNG shipping capacity in an effort to anticipate increasing spot LNG trade and the possible emergence of an LNG commodity market. They will have the opportunity of responding to price signals by moving cargoes to high-margin markets during periods of high-energy usage.

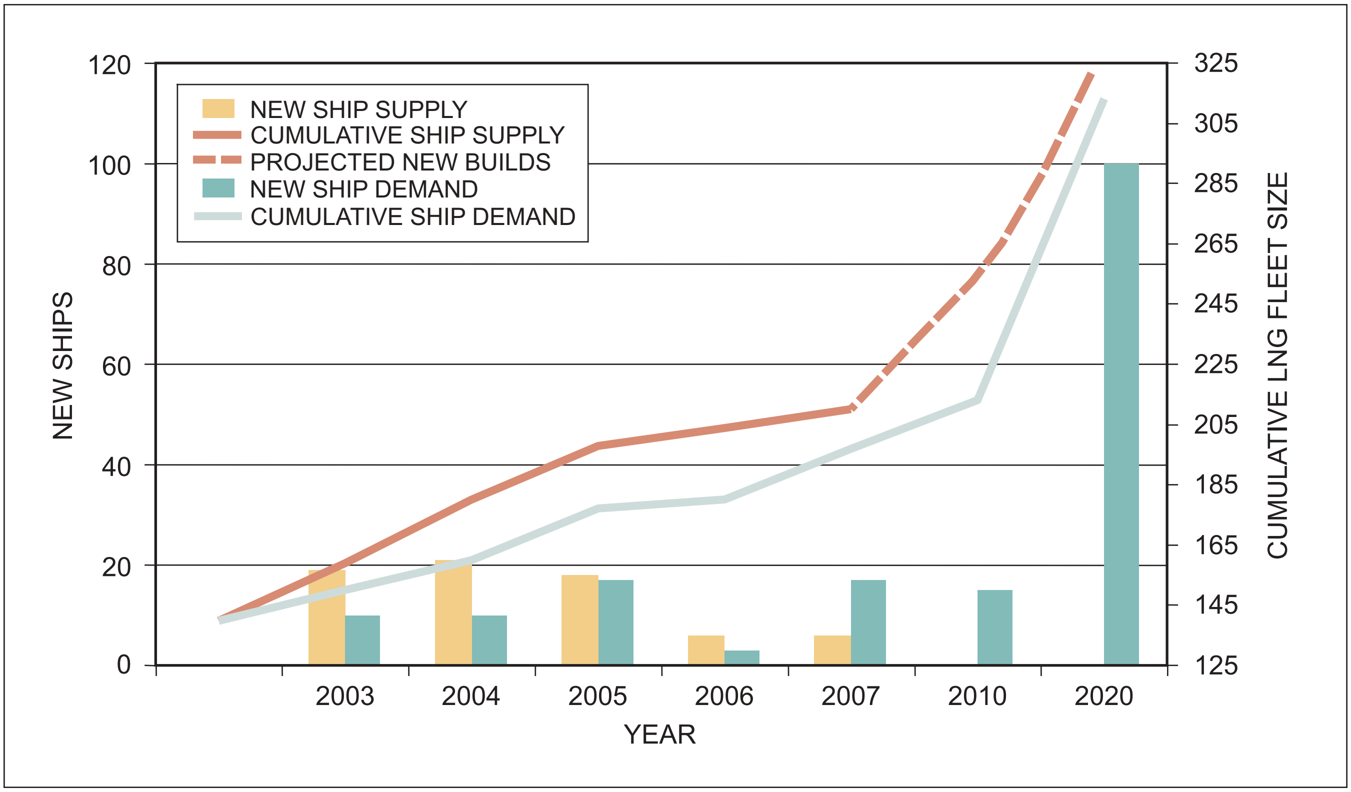


Figure L-13. Shipping Supply and Demand

Based on utilization of existing port facilities, LNG shipping costs are estimated to range as low as \$0.50/MMBtu for Atlantic trade with Trinidad to values as high as \$1.70/MMBtu for shipments from the Middle East. These costs are summarized in Table L-8. Shipping costs by country were previously shown in Table L-5.

D. Regasification Import Terminals

The growing demand for natural gas in the United States combined with rising natural gas prices has prompted the U.S. gas industry to announce or propose a slate of new terminal projects. These proposals are located in the continental U.S., both onshore and offshore, in the Bahamas, in the Mexican Gulf, and in Eastern Canada. Not all of these projects will be realized. The forecast of North American LNG import capacity over the next two decades used in this report is discussed in Section VI, with the results ranging from 12.5 BCF/D to as high as 15.0 BCF/D.

Region	Low	High
Pacific	0.60	1.20
Middle East	1.40	1.70
Atlantic Basin	0.50	1.00

Table L-8. Shipping Cost to U.S. by Region (Dollars per Million Btu)

Constructing new terminals and ports that provide safe operations will only occur with the support of the public, the regulatory authorities and investors. This support will only be forthcoming for sites that are strategically located and environmentally and economically suitable. Existing onshore terminals have a clear advantage for providing incremental new capacity at the lowest cost. As illustrated in Figure L-14, at 750 MCF/D expansion capacity is estimated to cost in the range of \$0.20 to \$0.45/MMBtu. The cost is slightly higher at lower capacities.

New terminal construction may require new investment for expanding existing infrastructure and for building or upgrading port facilities. There may be an additional burden associated with maintaining river or channel dredging programs, and there may also be

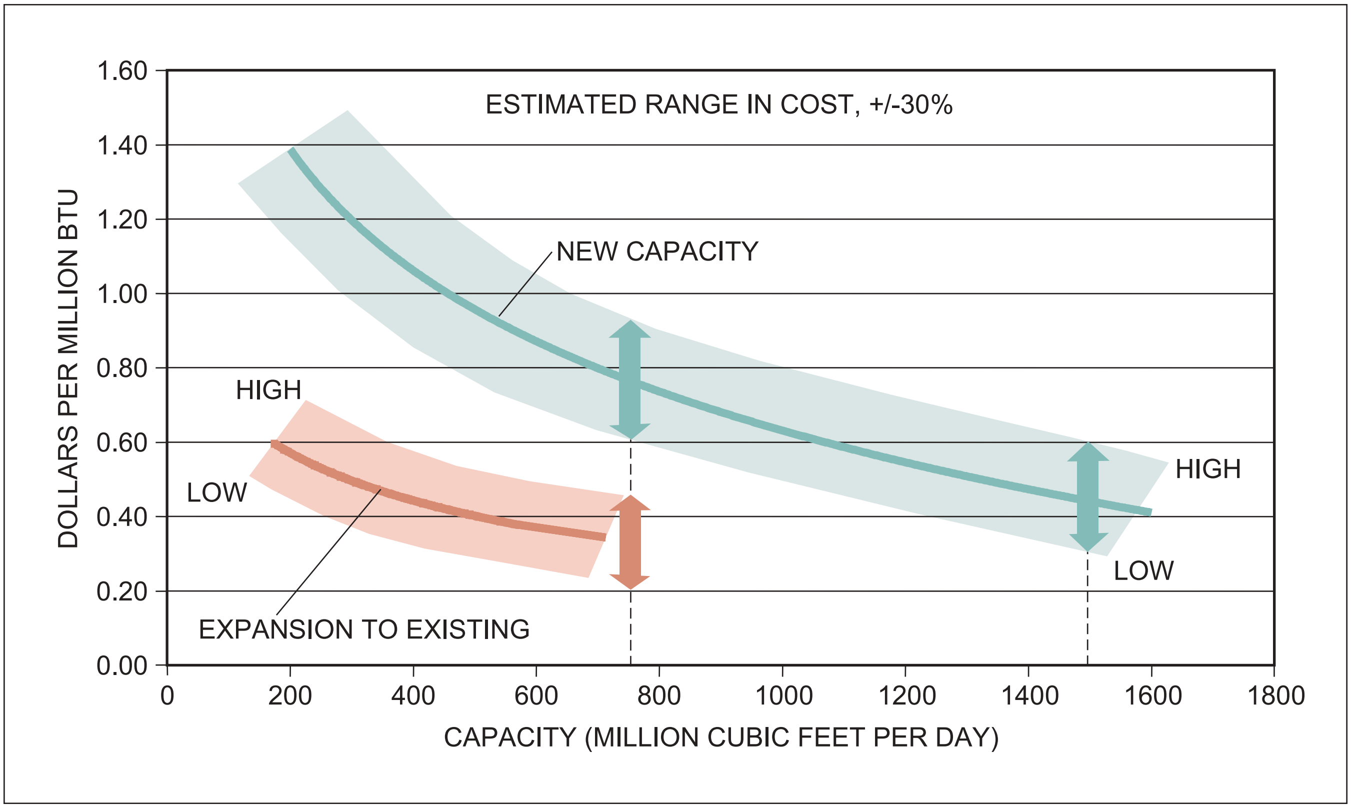


Figure L-14. U.S. LNG Terminal Cost – Expansion and New Capacity

higher port charges for increased tug boat assistance through congested port areas. As shown in Figure L-14, new onshore and offshore terminal capacity at 750 MCF/D may cost in the range of $0.60 to $0.90/MMBtu. Larger facilities would benefit from economies of scale. For example at 1,500 MCF/D, the cost for new terminal capacity is estimated to range from $0.30 to $0.60/MMBtu. Generally, to be commercially viable new terminals must plan on expanding unless the terminal is serving a niche market or a specific buyer. In summary, the cost of LNG terminal access and regasification range from $0.20 and $0.90/MMBtu. An estimate of $0.45/MMBtu is a reasonable estimate for a new project with expanded capacity.

E. U.S. Gas Marketing

The U.S. gas market is the largest in the world, highly liquid with the NYMEX contract at Henry Hub the most highly traded gas contract. This market has been highly developed over years of deregulation. Wholesale gas prices are established by negotiation between buyer and seller for gas delivered at a specific point.

A major strength of the U.S. natural gas industry is the highly developed, extensive infrastructure in place, particularly in the onshore and offshore regions of the U.S. Gulf Coast. The gas infrastructure includes a network of offshore and onshore pipelines, gas processing plants, underground gas storage facilities, and pooling points that provide for a highly liquid gas trading market serving the gas customers across the country. This infrastructure is illustrated in Figure L-15. The pipeline infrastructure provides easy supply access to local distribution companies, power plants, utilities, and major industrial users across the U.S., particularly serving the eastern half of the United States.

U.S. interstate gas pipeline transportation rates and services are subject to regulatory oversight and ratemaking of the Federal Energy Regulatory Commission (FERC). Transportation customers, however, that buy and sell natural gas and arrange transportation services with the pipeline are subject to market competition and commodity prices are not protected by FERC's regulation. The transport cost from the point of supply to the point of end use may be incurred by either the buyer or the seller, and there is no assurance that the transport cost will be recovered

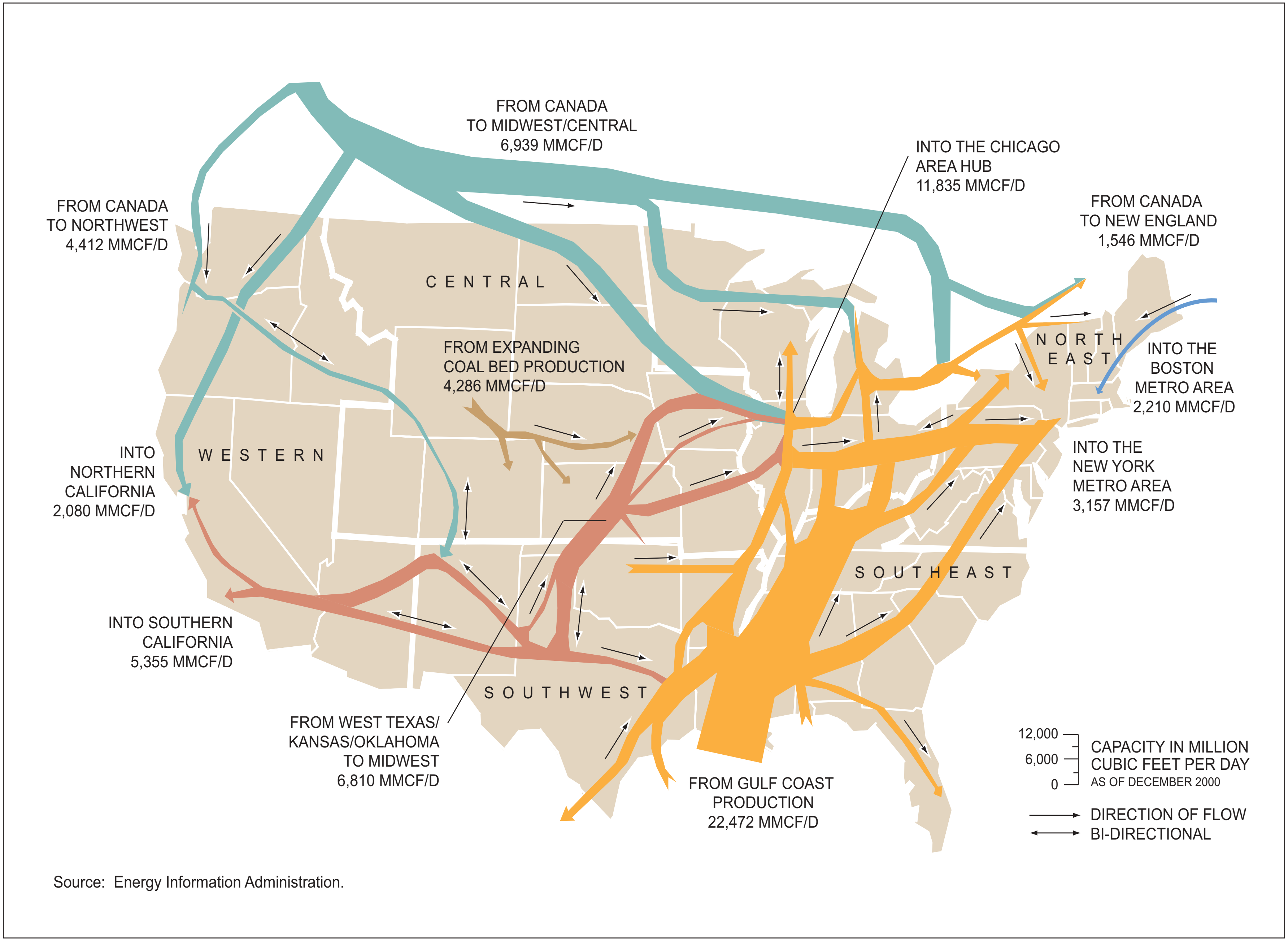


Figure L-15. U.S. Natural Gas Transportation Network by either one. Therefore, in this analysis transportation cost from LNG regasification terminal to the end-user is not considered.

F. Total Supply Cost

Table L-9 summarizes all aspects of the LNG value chain, from the cost of supplying natural gas from the LNG liquefaction plant tailgate (including the cost of feedstock gas), through shipping, U.S. receiving terminal and regasification for delivery into the U.S. gas pipeline grid. The cost of supplies from Atlantic Basin countries ranges from $1.80 to $4.90/MMBtu, from Middle East countries, $2.80 to $4.30/MMBtu, and from Asia Pacific countries, $2.30 to $5.40/MMBtu. A chart comparing the range and mid-point of country ranges is given in Figure L-16. The chart illustrates that at $3.50/MMBtu, about half of world's supplies would be attracted to U.S. markets, and at $5.00/MMBtu essentially all would be attracted to U.S. markets. Actual capture of supply, however, will depend on price competition with other world markets.

G. Alternative Gas Technologies

Two other types of technology are being developed to transport natural gas over long distances. One is called "Gas-to-Liquids" or GTL. This technology transforms the gas into a liquid at ambient conditions. Although this technology has yet to be commercially employed, it is a future potential competitor with LNG for developing stranded gas resources.

Another technology, compressed natural gas or "CNG" may be a potential solution for smaller gas resources to be shipped shorter distances. Compared to GTL and LNG, the process for making CNG is relatively low-tech. Natural gas is cooled to temperatures

Atlantic	FOB Supply Cost	Shipping Cost to GOM	Terminal & Regas Cost	Delivered LNG Cost to GOM
Angola	1.50 - 2.00	1.00	0.30 - 0.90	2.80 - 3.90
Eq.Guinea	1.00 - 1.50	1.00	0.30 - 0.90	2.30 - 3.40
Nigeria	1.00 - 3.00	1.00	0.30 - 0.90	2.30 - 4.90
Algeria	2.50 - 3.00	0.70	0.30 - 0.90	3.50 - 4.60
Egypt*	1.00 - 1.50	0.90	0.30 - 0.90	2.20 - 3.30
Norway	3.00 - 3.00	0.90	0.30 - 0.90	4.20 - 4.80
Trinidad	1.00 - 2.00	0.50	0.30 - 0.90	1.80 - 3.40
Venezuela	1.50 - 2.00	0.50	0.30 - 0.90	2.30 - 3.40
Middle East		**to GOM**		**to GOM**
Qatar	1.00 - 1.50	1.60	0.30 - 0.90	2.90 - 4.00
Iran	1.00 - 1.50	1.70	0.30 - 0.90	3.00 - 4.10
Oman	1.00 - 1.50	1.50	0.30 - 0.90	2.80 - 3.90
Yemen	1.50 - 2.00	1.40	0.30 - 0.90	3.20 - 4.30
Pacific		**to US WC**		**to US WC**
Australia	1.00 - 2.50	1.20	0.30 - 0.90	2.50 - 4.60
Indonesia	1.00 - 2.00	1.00	0.30 - 0.90	2.30 - 3.90
Malaysia	2.00 - 2.50	1.00	1.30 - 1.90	4.30 - 5.40
Peru	2.50 - 3.00	0.60	0.30 - 0.90	3.40 - 4.50
Bolivia	2.00 - 2.50	0.70	0.30 - 0.90	3.00 - 4.10
Russia	2.00 - 2.50	0.70	0.30 - 0.90	3.00 - 4.10

* Shipping cost comparatively lower due to higher Btu/CF content of gas.

Table L-9. Value Chain Costs to U.S. Markets (Dollars per Million Btu)

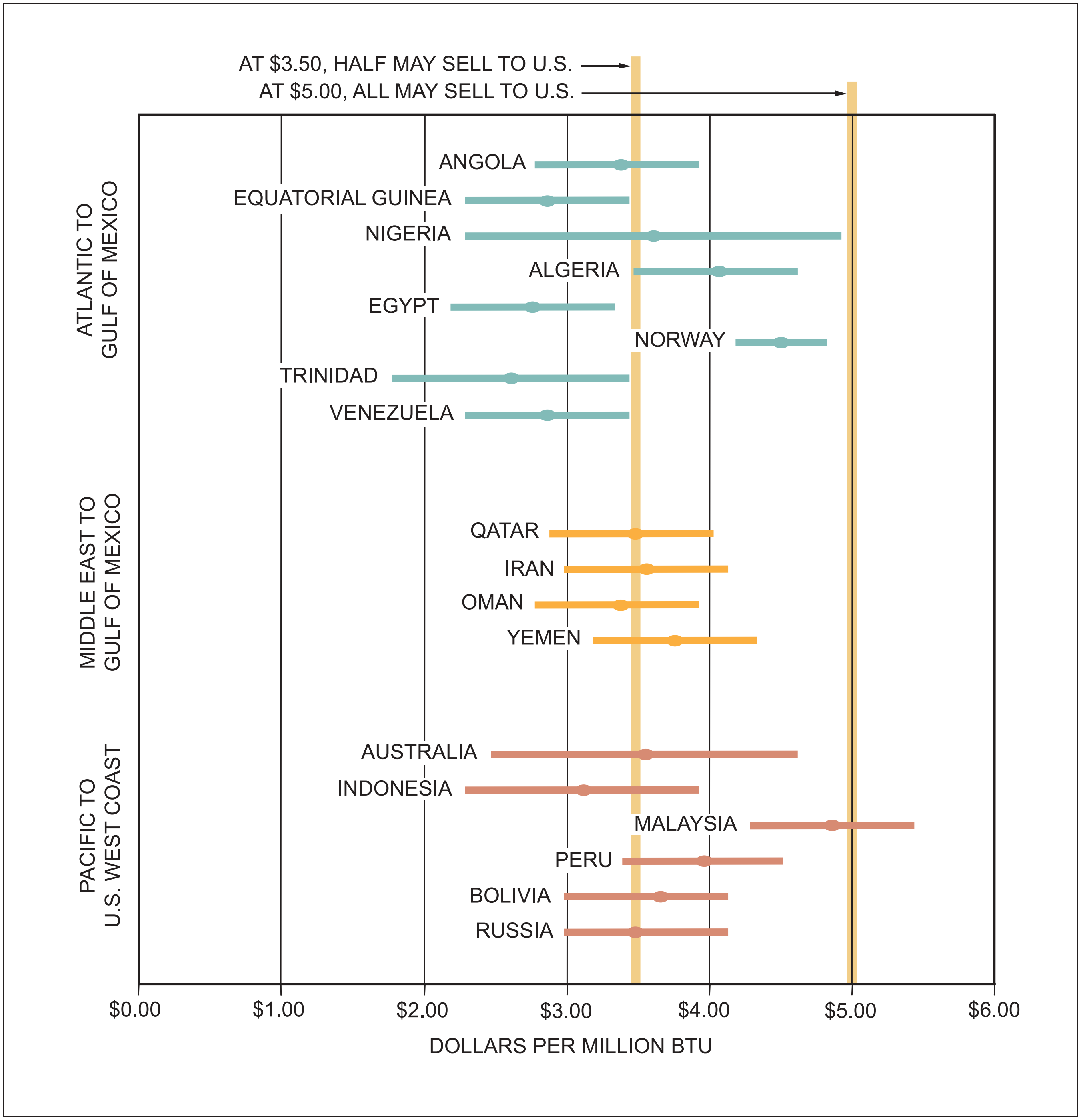


Figure L-16. Value Chain Costs to U.S. Gas Markets – Range and Mid-Point Values

below 32°F, compressed at high pressures, and transported in a specially designed containment system of pipes or tubing. The storage containment is integrated into a barge or ship of varying size depending on the application. Higher pressures will require stronger, heavier containment systems, but will allow for larger quantities of gas to be transported. The technical challenge is to optimize the design, taking into account the weight of the containment system, gas quantities, size and speed of the carrier, as well as other factors in order to provide the most cost-effective transportation system.

CNG technology is still in a process of evolution and a more complete description can be found in Appendix D, "Compressed Natural Gas."

V. LNG in the United States

A. History

There are two basic types of LNG facilities in operation in the world today. The first, commonly called peak-shaving facilities, are typically smaller units, often located close to major market demand areas. Their primary purpose is to provide gas for exceptional peak demand periods. In terms of function, they are analogous to the subsurface storage facilities used to modulate peak day demand. This type of LNG facility typically takes gas from the grid in low demand periods, liquefies it and then stores it ready for the peak demand periods.

The second type of LNG facility acts as a conduit for the importation of large volumes of generally baseload supplies. In this case, gas is liquefied close to the production point and is transported to its market in insulated LNG tankers that keep the hydrocarbons in a liquid state. It is this second category of "baseload" LNG supply that is addressed in this section of the study.

The United States currently has four baseload LNG receiving terminals with a sustained sendout capacity of about 3.2 BCF/D. These include the Distrigas (Tractebel) terminal at Everett, Massachusetts (700 MMCF/D capacity), the Trunkline LNG (Southern Union) terminal at Lake Charles, Louisiana (1,000 MMCF/D), the Dominion terminal at Cove Point, Maryland (1,000 MMCF/D), and the Southern LNG (El Paso) terminal at Elba Island, Georgia (450 MMCF/D). All four facilities were constructed between 1971 and 1982 but never reached their full potential because LNG has historically not been competitive with domestic pipeline gas in the U.S. marketplace.

The facilities, other than Everett, were constructed pursuant to Section 7(c) certificates (Natural Gas Act) issued by the Federal Energy Regulatory Commission (FERC) or its predecessor, the Federal Power Commission. The FERC originally disclaimed jurisdiction over the Everett terminal as it was focused on selling liquid and vaporized LNG supplies directly to local distribution companies in the region. As a consequence, it was constructed without the requirement for Section 7 approvals. Subsequent court decisions determined that the FERC had jurisdiction under Section 3 of the Gas Act and could use that authority to impose essentially the same conditions as would apply under Section 7. The FERC retroactively authorized construction, but subject to Section 7-like requirements.

Other than the Everett location, the purpose of the terminals was to provide system supply gas in support of an interstate pipeline's transportation and merchant functions. The pipeline owners entered into long-term, take-or-pay contracts with international suppliers, namely Algeria. However, unlike many of the LNG terminals present in other parts of the world, the contracts typically did not cover all of the terminal's capacity. Subsequent changes in the supply situation to the U.S. gas market led to the mutual early termination of most of the supply agreements. As a result, both Cove Point and Elba Island were mothballed in the early 1980s. The two operating terminals (Everett and Lake Charles) have periodically been idle but generally continued to operate at a fraction of their designed throughput capacity.

This situation has changed dramatically over the past several years as the balance of supply and demand in the United States has tightened considerably over the past few years. With the perceived need for additional supply to keep pace with future demand growth, both Cove Point and Elba Island have been reactivated and the Everett terminal has been expanded. The Lake Charles facility is currently undergoing an expansion and expansion plans have been announced at both Elba Island and Cove Point.

The reactivation process entailed the submission of a number of petitions to the FERC regarding cost structures, rates and other tariff terms and conditions, existing contracts, and projected capacity utilization. In response to these petitions, the FERC has issued orders that clarify how major industry restructuring, which the U.S. gas industry has undergone since these terminals were last operated, impacts operating conditions of the terminal. Some of these orders, specifically the mandatory requirement that LNG operators must offer open access to terminal capacity via open seasons and cost-of-service based tariffs, were seen by developers as a potential impediment to building new LNG terminals in the United States. Accordingly, in its "State of the Industry" conference held in October 2002, the Commission included regulatory roadblocks to new LNG terminal development as one of its major topics of discussion. In both meeting presentations and post-conference comments, all segments of the industry confirmed that the Commission's policy of treating LNG terminals on the same regulatory basis as interstate gas pipelines was seen as a hindrance to new infrastructure development.

As a result, new regulatory policies governing both offshore and onshore LNG terminal were introduced in late 2002. For offshore terminals, Congress enacted the Maritime Transportation Security Act, which amended the Deepwater Port Act of 1974 by adding natural gas, including LNG, to its framework. The significance of this change is that offshore LNG terminals will hereafter be treated as Deep Water Ports and as such, will come under the jurisdictional authority of the U.S. Coast Guard. These ports will be proprietary and will be treated in much the same manner as offshore production facilities. Onshore, FERC adopted a similar less intrusive approach for regulating the commercial structure of LNG terminals as a result of its ruling on the proposed Hackberry LNG (now Cameron LNG) terminal. These changes mean that project developers can now operate new facilities, both onshore and offshore, on a proprietary access basis and at market-determined rates.

B. Description of Existing Terminals/ Infrastructure

As mentioned above, the United States currently has four LNG receiving terminals currently in operation. These terminals range in size from 450 MMCF/D to 1,000 MMCF/D based on sustainable regasification and sendout capacity. Terminal sendout is determined by vaporization (regasification) capacity and pipeline access, and to a lesser degree, on-site storage capacity and tanker berth space. Table L-10 details the operational characteristics of each of these facilities as well as their potential expansion capability.

Facility (Owner)	Base Capacity (MMCF/D)	Peak Capacity (MMCF/D)	Storage Capacity (BCF)
Everett, MA (Tractebel)			
Existing	435	550	3.50
Planned expansion (2005)	480	600	0.85
Total with expansion	915	1,150	4.35
Elba Island, GA (El Paso)			
Existing	445	675	4.00
Planned expansion (2005)	360	540	3.30
Total with expansion	805	1,215	7.30
Lake Charles, LA (CMS)			
Existing	630	1,000	6.30
Planned expansion (2005)	570	300	3.00
Total with expansion	1,200	1,300	9.30
Cove Point, MD (Dominion)			
Existing	750	1,000	5.00
Planned expansion (2005)	250	320	2.80
Total with expansion	1,000	1,320	7.80
Total Existing	**2,260**	**3,225**	**18.80**
Total Expansion	**1,660**	**1,760**	**9.95**
Total With Expansion	**3,920**	**4,985**	**28.75**

Source: Energy Information Administration, Office of Oil and Gas, January 2003.

Table L-10. Existing North America LNG Terminals and Planned Expansions

1. Everett, Massachusetts

The Distrigas terminal (now controlled by Tractebel) is located in Everett, Massachusetts, near Boston. The terminal was completed in 1971 on a 34-acre, protected deepwater site inside Boston Harbor. The facility is the oldest LNG import terminal in the United States. It has a storage capacity of 3.5 BCF in two LNG storage tanks and a sendout capability of 0.44 BCF/D into three pipeline systems serving customers throughout the northeast (Tennessee Gas Pipeline, Algonquin Gas Transmission, and the local distribution network of KeySpan Energy Corporation). The facility also supplies LNG to customers via truck with an additional sendout of 0.1 BCF/D. Expansion of the terminal by an additional 0.15 BCF/D has recently been completed in order to serve a new power plant located close to the site.

The Everett terminal is the only one that has been in near continuous operation since its construction. It receives LNG primarily from Trinidad with winter supplies from Algeria. The terminal can receive LNG up to a heat content of 1,080-1,090 Btu/CF without pipeline restriction.

2. Lake Charles, Louisiana

Located in southeastern Louisiana, the Lake Charles terminal was completed in 1981 on a 382-acre site in the Lake Charles Harbor and Terminal District close to the city of Lake Charles. Trunkline LNG, a subsidiary of Southern Union Panhandle, is the current owner. The terminal was mothballed in 1983 due to the availability of lower cost pipeline gas supplies. It re-opened in 1989 and has been in operation since that time, albeit at less than its design capacity.

Lake Charles has three LNG storage tanks with a combined capacity of over 6.3 BCF. Peak sendout capacity is 1 BCF/D, with a sustainable sendout of 0.63 BCF/D. There are plans to expand the terminal to a storage capacity of 9 BCF and a 1.2 BCF/D sustainable sendout by 2005. Currently, British Gas (BG) and Duke Energy have rights to the sendout capacity. Upon expiration of Duke Energy's commitment in 2005, BG will have rights to 100% of the terminal capacity.

With close proximity to the pipeline grids in the Gulf of Mexico, the terminal is able to access most of the major U.S. markets. As a result of this proximity, richer LNG sources can be blended down in heating values or processed to reduce heating values making the terminal potentially available to receive LNG from most sources in the world. Lake Charles can typically accept LNG with a heating range of 1,012-1,120 Btu/CF, and up to 1,200 Btu/CF according to its published tariff.

3. Cove Point, Maryland

The Cove Point terminal is located on 1,017 acres of land on the western shore of Chesapeake Bay, 40 miles south of Annapolis, Maryland. The terminal was completed in 1978 under the ownership of Columbia LNG Corporation and operated as an import terminal for two years, receiving supply from Algeria. Cove Point was placed back into service in 1995 as a peak-shaving storage facility. Williams took over as operator in 2002 and subsequently sold it to a subsidiary of Dominion Resources in 2003. The LNG terminal was reactivated and received its first cargo in the third quarter of 2003.

Cove Point has the capability to handle two LNG tankers simultaneously, although only one can be unloaded at a time. The actual unloading facility is offshore and is connected to the unloading facility by a 1.25-mile underwater tunnel. The terminal has four storage tanks with a combined storage capacity of approximately 4.9 BCF. Maximum vaporization capacity is 1 BCF/D, including 0.25 BCF/D for peaking. A fifth storage tank, with 2.88 BCF of capacity, is under construction. Currently, BP, Shell, and Statoil each hold one-third (0.25 BCF/D) of baseload sendout capacity, the result of a previous open season.

The facility includes a pipeline connection directly to the Columbia, Transco, and Dominion transmission systems. Cove Point's tariff restricts the heating content of the vaporized LNG to a maximum of 1,100 Btu/CF, which largely limits current imports to Trinidad. As a result, a nitrogen injection facility is being installed that will blend nitrogen with regasified LNG as a means of expanding its access to global supply sources.

4. Elba Island, Georgia

Located near Savannah, Georgia, the Elba Island terminal is operated by Southern LNG, Inc., a subsidiary of El Paso Corporation. The terminal was completed in 1978, mothballed in 1980, and re-opened in 2001 for baseload operation.

The terminal encompasses approximately 140 acres on Elba Island in an estuary of the Savannah River. A secure, private bridge provides road access to the site. Three storage tanks provide a combined capacity of 4.2 BCF, with a fourth tank under construction for its expansion in 2005. Sustainable sendout capacity is 0.45 BCF/D, with a peak sendout baseload of 0.675 BCF/D. An expansion to 0.8 BCF/D baseload and 1.2 BCF/D peak is planned for late 2005 (when a 3.3 BCF addition will bring storage capacity to 7.5 BCF). El Paso Merchant Energy holds the rights to all the present capacity at the terminal, with British Gas and Marathon entitled to supply 0.29 BCF/D and 0.15 BCF/D, respectively. Shell holds all of the post-2005 expansion capacity. The terminal accepts LNG up to 1,075 Btu/CF heat content.

C. Announced LNG Terminal Projects

LNG is expected to play an ever-increasing role toward meeting the future energy needs of the United States. A number of factors are contributing both to the rise in current LNG demand as well as the plans for the expansion of existing terminals and the construction of new facilities. These include a projected gap between domestic natural gas supply and growth in demand, higher natural gas prices, and technological advances that have lowered costs for LNG liquefaction, shipping, storage and regasification. There is also an increase in the number of potential sources of LNG into the U.S. as suppliers are drawn by market size and liquidity.

Several companies have announced plans for the construction of new LNG import terminals to serve the U.S. market. While it is uncertain how many of these projects will actually come to fruition, the FERC has announced that they are currently reviewing sixteen planned and three proposed terminals on the U.S. coasts and the Bahamas (with regard to the latter, the FERC has jurisdiction only on the pipeline connection to the United States). In addition, the Coast Guard is reviewing two proposed offshore terminals with others recently announced. Figure L-17 shows the locations of many of the proposed terminals. Table L-11 gives

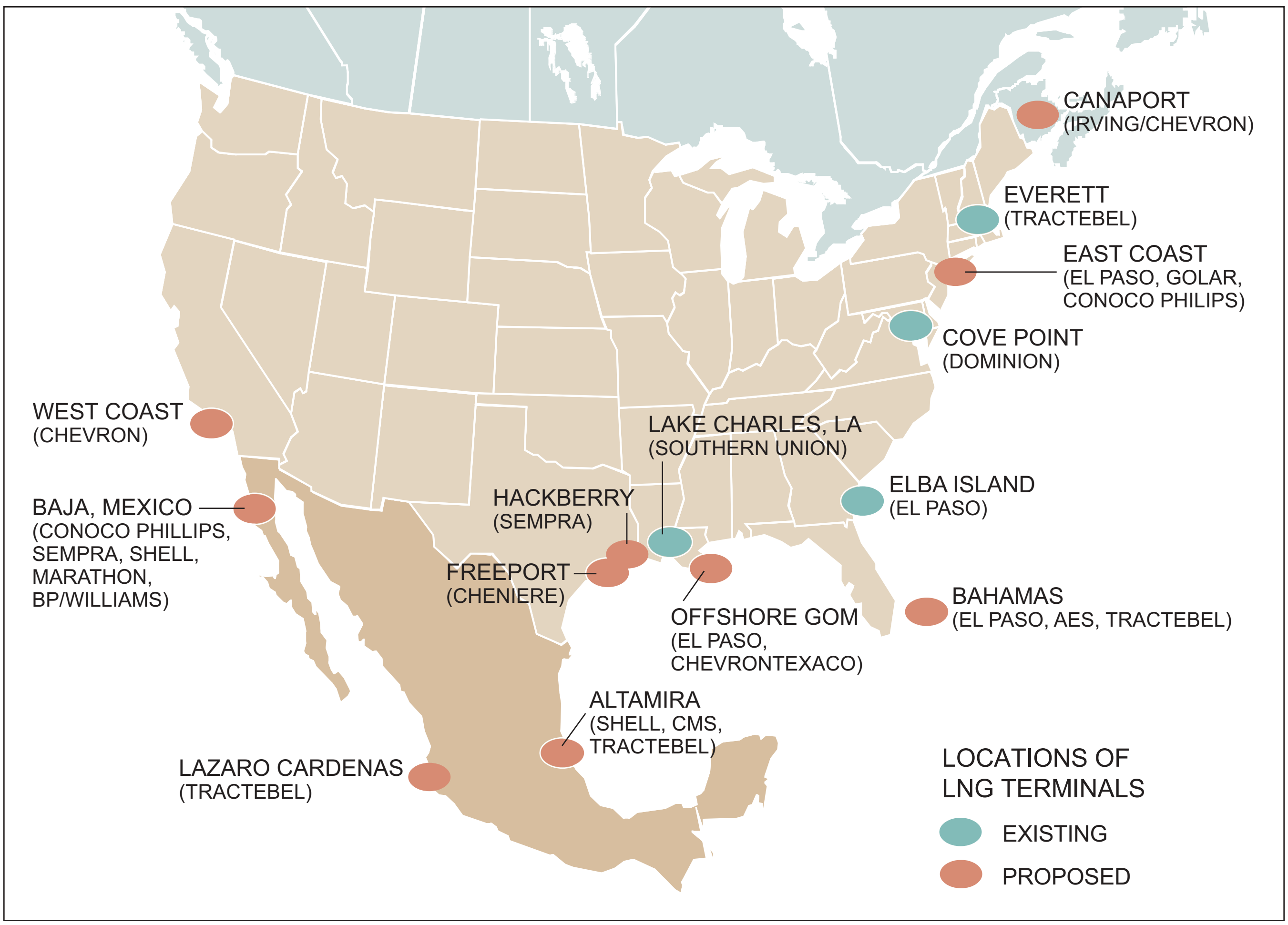


Figure L-17. Existing and Proposed North American LNG Import Terminals

Owner(s)	Project/Location Name	Status	In-Service Date	Capacity (MMCF/D)	Comments
AES	Ocean Cay, Bahamas	Filed	2007	800	Includes pipeline to Florida; received FERC preliminary determination.
Bechtel	Mare Island, California	Planned	2007	1300	Was partnered with Shell.
BP/Williams	Baja	Planned	NA	NA	No public announcement yet.
Cheniere Energy	Freeport, Texas	Planned	2006	650	Announced land lease options obtained; FEED and environmental studies underway.
Cheniere Energy	Sabine Pass, Texas	Planned	2007	650	Announced land lease options obtained.
Cheniere Energy	Brownsville, Texas	Planned	2007	650	Announced land lease options obtained.
ChevronTexaco	Port Pelican, Gulf of Mexico	Filed	2007	800	Submitted offshore application to Coast Guard.
ChevronTexaco	Offshore Baja	Planned	2007	NA	Is looking at offshore terminal.
ConocoPhillips	Baja (Rosarito Beach)	Planned	2008	620	Permit application sent back by Mexico Environment Ministry. Was partnered with El Paso.
Crystal Energy	Offshore Southern California	Planned	2007	550	Has signed a long-term lease with platform owner. Filing planned late 2003.
El Paso	Bahamas	Planned	2005	550	Includes pipeline to Florida. Filing with Bahamian authorities made. Project for sale.
El Paso	Energy Bridge Gulf of Mexico	Filed	2006	500	Tankers to hook up to offshore buoy. Submitted offshore application to Coast Guard
El Paso	Energy Bridge Northeast	Planned	2008	500	Tankers to hook up to offshore buoy.
Golar LNG	Offshore Atlantic	Planned	2004	400	Conversion of Golar Freeze to floating fixed regas terminal.
Irving Oil	Canaport, St. John, New Brunswick	Planned	NA	500	Existing deepwater port.
Marathon	Baja (Tijuana)	Filed	2006	1,000	Has filed with Mexico's Energy Regulatory Commission.
Sempra	Cameron LNG (Hackberry), Louisiana	Filed	2007	1,500	LNG tankers must travel Calcasieu River (same as Lake Charles tankers); Dynegy sold project to Sempra in February 2003. Received FERC preliminary determination.
Sempra	Baja (Ensenda)	Filed	2006	1,000	Received Mexican environmental permit. Has filed with Mexico's Energy Regulatory Commission.
Shell	Baja (Costa Azul)	Filed	2007	1,300	Received Mexican environmental permit. Has filed with Mexico's Energy Regulatory Commission.
Shell	Altamira	Planned	2006	700	Received Mexican environmental permit. Has filed with Mexico's Energy Regulatory Commission. Was partnered with El Paso.
Tractebel	Calypso LNG, Bahamas	Filed	2006	832	Includes 42-mile pipeline to Florida. Pipeline has received preliminary determination and Bahamian government is reviewing the project. Purchased project from Enron.
Tractebel	Lazaro Cardenas, Mexico	Planned	NA	NA	Tractebel says detailed Mexico plan not ready until end of 2002; Supply could come from Peru as Tractebel is distributor of Camisea gas in Peru.
Weaver's Cove Energy (Poten)	Fall River, Massachusetts	Planned	NA	NA	Existing port. Plan to build pipeline along right-of-way of existing crude line.

Table L-11. Announced North American LNG Import Terminal Projects (Current as of First Half of 2003) details on the terminal projects that have been announced for North America (including Mexico).

D. Historical LNG Imports

U.S. LNG imports into the United States remained low from 1970 until the completion of both the Cove Point and Elba Island terminals in 1978, as shown in Figure L-18. LNG imports reached a peak the following year at 252.6 BCF, which represented 1.3% of total U.S. consumption. Due to falling natural gas demand coupled with rising domestic supply and price disputes with Algeria (the only LNG supplier to the U.S. prior to 1996), imports declined rapidly in the 1980s and remained low throughout most of the 1990s. As U.S. supply and demand became more in balance in the late nineties, producing a rise in gas prices, LNG imports increased, primarily with the introduction of new Trinidad supply. Since 1997, a total of nine countries have exported LNG to the United States.

In 2002, the three operating U.S. terminals imported 228.7 BCF, which represents about 1% of total U.S. gas consumption. Through the first half of 2003, LNG imports to the U.S. have totaled 204.4 BCF, nearly equal to the total for the previous year.

VI. North American LNG Import Forecasts

The NPC LNG forecasts developed in this study depend on many assumptions. These include assumptions about North American market demand and pricing, international LNG supply availability and cost, the availability of LNG ships, the number, location, and timing of terminal expansions, regulatory and permitting issues, and public opposition.

A. Study Approach

The team made use of publicly available data to identify potential North American LNG import terminal locations and to estimate the timing of LNG imports. The approach used was to:

- Research and develop estimates of LNG supply, transportation, and regasification costs
- Utilize announcements of potential new U.S. LNG import terminals and global LNG supply
- Evaluate the competitive global LNG market

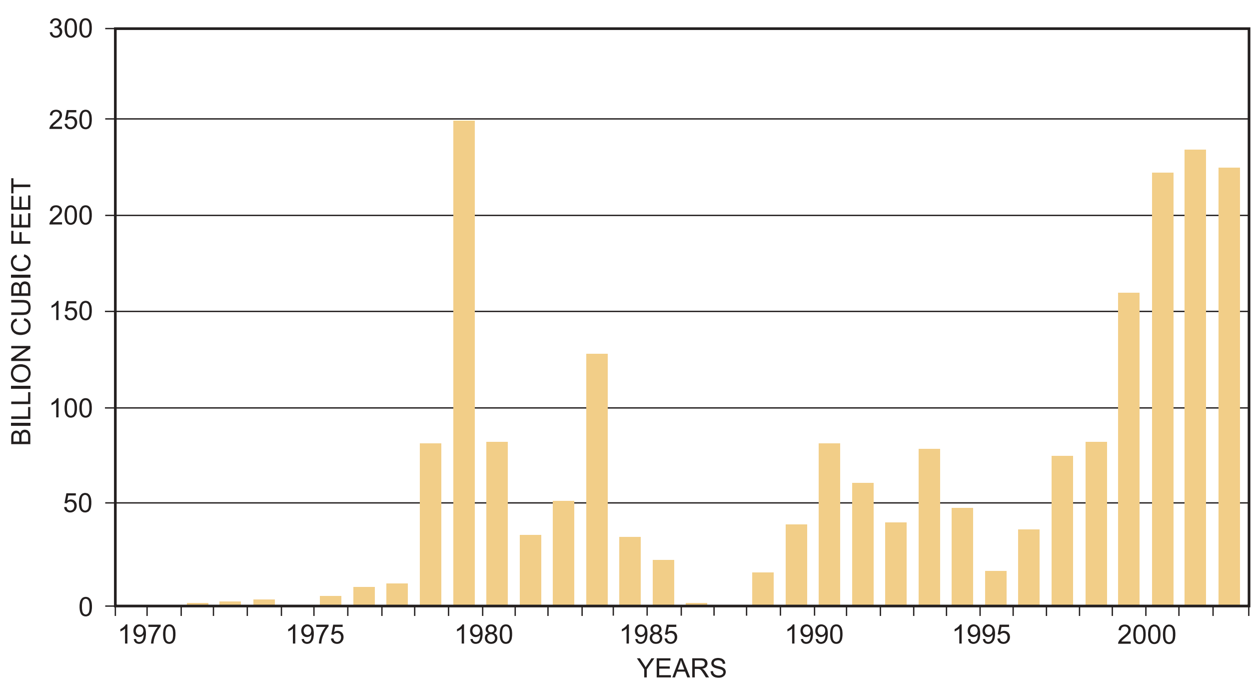


Figure L-18. Historical Annual U.S. LNG Imports

- Establish "standard" model assumptions for timing of terminal permitting and construction, terminal size, and buildup of imports

- Identify the timing of potential supply and LNG import terminal additions

- Identify "controlling" assumptions that might affect the pace of new LNG imports

- Develop three scenarios for use in modeling input

- Identify issues that might affect the pace of LNG imports

- Compile and use research in support of the LNG discussion

- Propose recommendations to address the identified issues.

B. Model Assumptions

The inputs for the LNG cases were exogenous to the model, meaning the volume profile was hard coded and not determined by the model. This treatment is based on the assumption that most of the projected LNG imports will be long-term base-load volumes. Once the development decision is made for these capital-intensive projects, these volumes should not be affected to any great extent by daily or monthly fluctuations in prices. The exogenous inputs include terminal locations/nodes, volumes, and timing of imports.

The following is a summary of the key model assumptions:

- Long-term prices support increased LNG imports

- New terminals sized for 750 MMCF/D base load

- New terminal expansions sized for 750 MMCF/D base load

- New terminal permitting time of 2 years

- New terminal construction time of 3 years

- Ramp-up rate of 3 years upon commencement of imports

- Existing U.S. LNG terminals supplied first, followed by their expansions, followed by new build terminals

- Location of new terminals driven by available downstream pipeline access and ease of permitting

- Timing of imports driven by supply availability, shipping, and new LNG import terminal development

- Limited shipping and LNG supplies available in the near term.

The outputs from the model runs indicate that U.S. long-term natural gas prices will support an increase in LNG imports. Dependent on supply development cost, location, and transportation cost, LNG can be imported into North America in a range of $2.00 to $4.00. Since the supply cost was determined not to be the critical assumption affecting LNG imports, the team focused on the assumptions with respect to timing and potential quantity of LNG imports.

The existing U.S. LNG import terminals have a base-load (continuous, steady) capacity of 400-750 MMCF/D. Many of the recently announced LNG terminals are in the 700 MMCF/D to 1.5 BCF/D range. Although the capacity of new terminals will likely vary, the team elected to use a generic size of 750 MMCF/D, with expansions of 750 MMCF/D. The only exception is a terminal located in Baja California. Because the recently announced proposals for terminals there are for 1 BCF/D, the model assumed 1 BCF/D for this terminal. The model inputs assume these volumes (750 MMCF/D or 1 BCF/D) are base-load volumes, not peak-load volumes.

The rate of entry of additional LNG imports will be primarily driven by the time required to secure permits and construct new LNG import terminals. Upon application, the permitting process for an onshore U.S. LNG import terminal can take two to three years. The timing for an offshore terminal is approximately one year. Construction of an onshore terminal would take about three years; offshore terminals may take slightly longer. Combining these factors, the team assumed that each new terminal development would take five years to complete (two years for permitting and three years for construction).

A buildup of three years was assumed for each new terminal before full utilization was to be achieved. This assumption is not caused by market demand restraints but is due to the combination of supply development and new ship construction. LNG competes in a global marketplace with significant growth potential, not only in North America, but also in Asia and Europe. This competition and anticipated growth means that growth will be constrained by limitations of key resources needed by upstream supply projects and by the availability of suitable shipyards for building new LNG carriers. LNG supply liquefaction facilities are typically constructed in series of processing units referred to as trains. Depending on size, multiple trains are typically constructed one to two years following the initial train. This construction profile impacts the LNG supply availability, resulting in a buildup profile.

The model assumes the four existing U.S. terminals will first be fully utilized, then expanded (three expansions have been announced to date). Once the existing terminals and their expansions are fully utilized, additional volumes will come from new terminal development. The locations of the new terminals are driven primarily by three factors: the availability of existing or potential expansion of downstream pipelines, the perceived ease of permitting, and other physical constraints. The bulk of the new U.S. based terminals modeled are located in the Gulf of Mexico coast due to (1) declining Gulf of Mexico shelf production, (2) spare capacity of existing infrastructure, (3) the availability of deepwater ports (onshore) or existing offshore pipeline systems (offshore), and (4) the perceived ease of permitting (as compared to other U.S. locations). Due to the growing gas demand in the northeast, two new LNG terminals are assumed to be built along the northeast coast. Two terminals are modeled for Mexico, one on the east coast and one on the west coast. These terminals are needed to meet the growing demand for natural gas in Mexico and California.

C. Case Descriptions

Three LNG case scenarios were developed. These were the Reactive Path scenario, the Balanced Future scenario, and a Low Sensitivity case. Each of the three cases indicate significant increases in LNG imports, growing from a base of about 600 MMCF/D beginning in 2003.

Table L-12 is a summary of the three input cases. Each of the scenarios shows a growing demand for LNG in North America in every year of the forecast. This is due to increasing U.S. natural gas prices, combined with new LNG supply and reduced LNG supply cost.

Year	Reactive Path	Balanced Future	Low Sensitivity
2000	0.6	0.6	0.6
2005	2.3	2.3	2.3
2010	7.3	7.5	5.5
2015	8.8	10.7	5.8
2020	11.6	13.3	6.5
2025	12.5	15.0	6.5
Total # of Terminals			
Existing Terminals	4	4	4
New Terminals	7	9	2
Expansions*	7	9	4

* Includes three expansions of existing terminals.

Table L-12. NPC LNG Scenarios North America LNG Imports (Billion Cubic Feet per Day)

All scenarios assume the four existing terminals will be fully utilized by late 2007 (when supplies become available) and that all expansions will be constructed and fully utilized by the end of the decade. This baseline will result in an increase in LNG imports of up to 3.9 BCF/D by 2010.

1. Reactive Path Scenario

In addition to the baseline, the Reactive Path scenario includes a total of seven new import terminals and the expansion of four of the new terminals. This scenario includes the development of five new import terminals by 2010. Two additional terminals and the expansions of four new terminals are added between 2010 and 2020. Figure L-19 shows the potential locations for these terminals. The import volumes gradually increase from 600 MMCF/D in 2003 to a peak of 12.5 BCF/D by 2025, as shown in Figure L-20.

Reactive Path Assumptions

- Existing terminals are fully utilized by 2007
- Existing Terminal Expansions
  + 2005 - Lake Charles and Elba
  + 2007 - Cove Point

Figure L-19. LNG Terminal Locations – Reactive Path Scenario

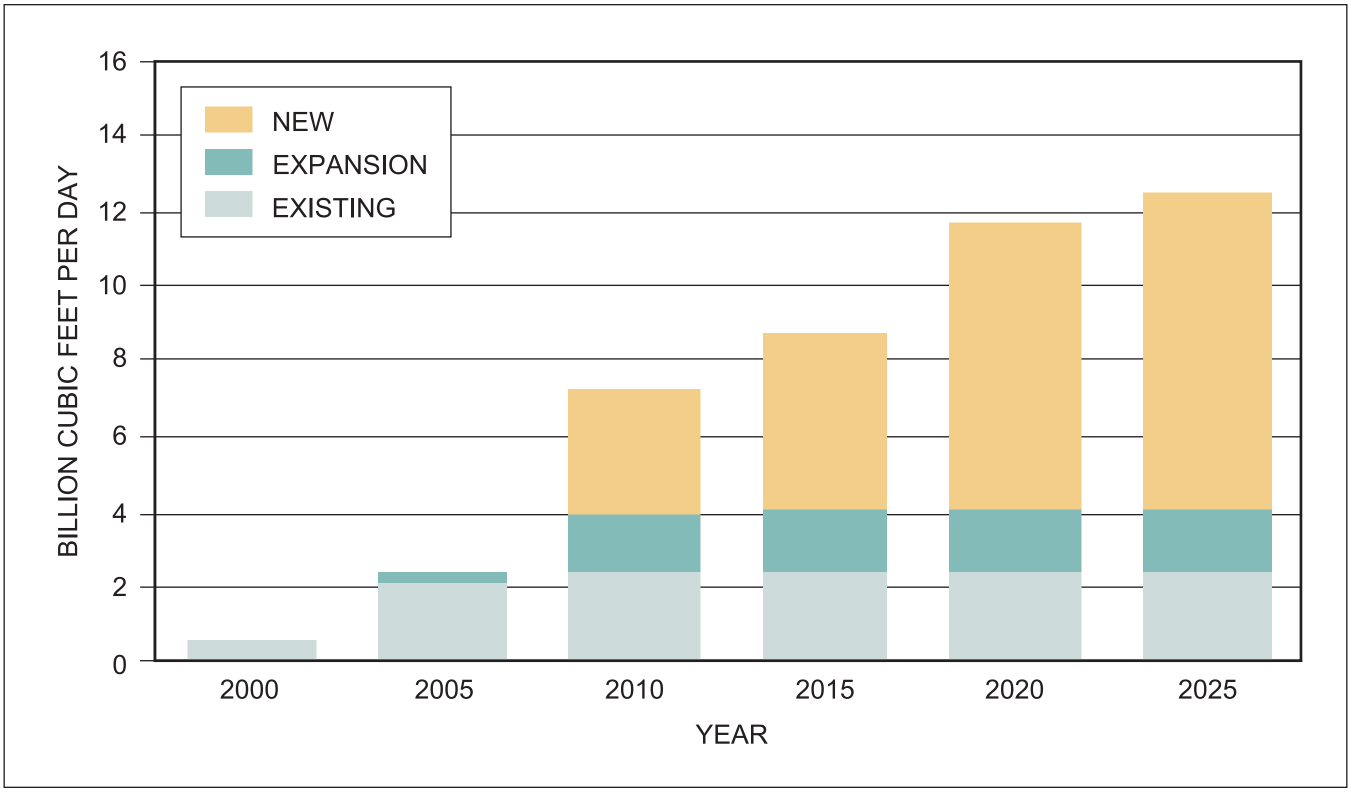


Figure L-20. North American LNG Imports – Reactive Path Scenario

- New Terminals
  - 2007-2010: 5 Total
    - Gulf of Mexico #1 & #2 (2007, 2009)
    - Northeast #1 (2009)
    - East Coast (Altamira) Mexico (2007)
    - West Coast (Baja) Mexico (2008)
  - 2010-2020: 2 Total + 4 Expansions
    - Gulf of Mexico #3 (2012)
    - Northeast #2 (2020)
    - Gulf of Mexico #1, #2, & #3 Expansions (2016, 2018, 2020)
    - Northeast #1 Expansion (2016)

2. Balanced Future Scenario

The Balanced Future scenario builds from the Reactive Path scenario and assumes increased LNG supply and shipping availability, along with less delay in import terminal permitting. This scenario incorporates two additional terminals, one in Bahamas (serving the Florida market) and one on the U.S. West Coast. The Balanced Future scenario also includes expansions of the second Northeast terminal and an expansion of the Florida terminal, and it accelerates start-up of the new terminals by one year. Figure L-21 shows the locations for these potential terminals.

In addition to the baseline, the Balanced Future scenario includes a total of nine new import terminals and the expansion of six of the new terminals. The Bahamas terminal is developed in 2010, with an expansion by 2012. The second Northeast terminal is accelerated to 2011, with an expansion in 2023. The West Coast terminal will be developed in 2021. The import volumes gradually increase from 600 MMCF/D in 2003 to a peak of 15.0 BCF/D by 2025, as shown in Figure L-22.

Balanced Future Assumptions (additions to Reactive Path highlighted in **bold**)

- Existing terminals are fully utilized by 2007
- Existing Terminal Expansions
  - 2005 - Lake Charles and Elba
  - 2007 - Cove Point

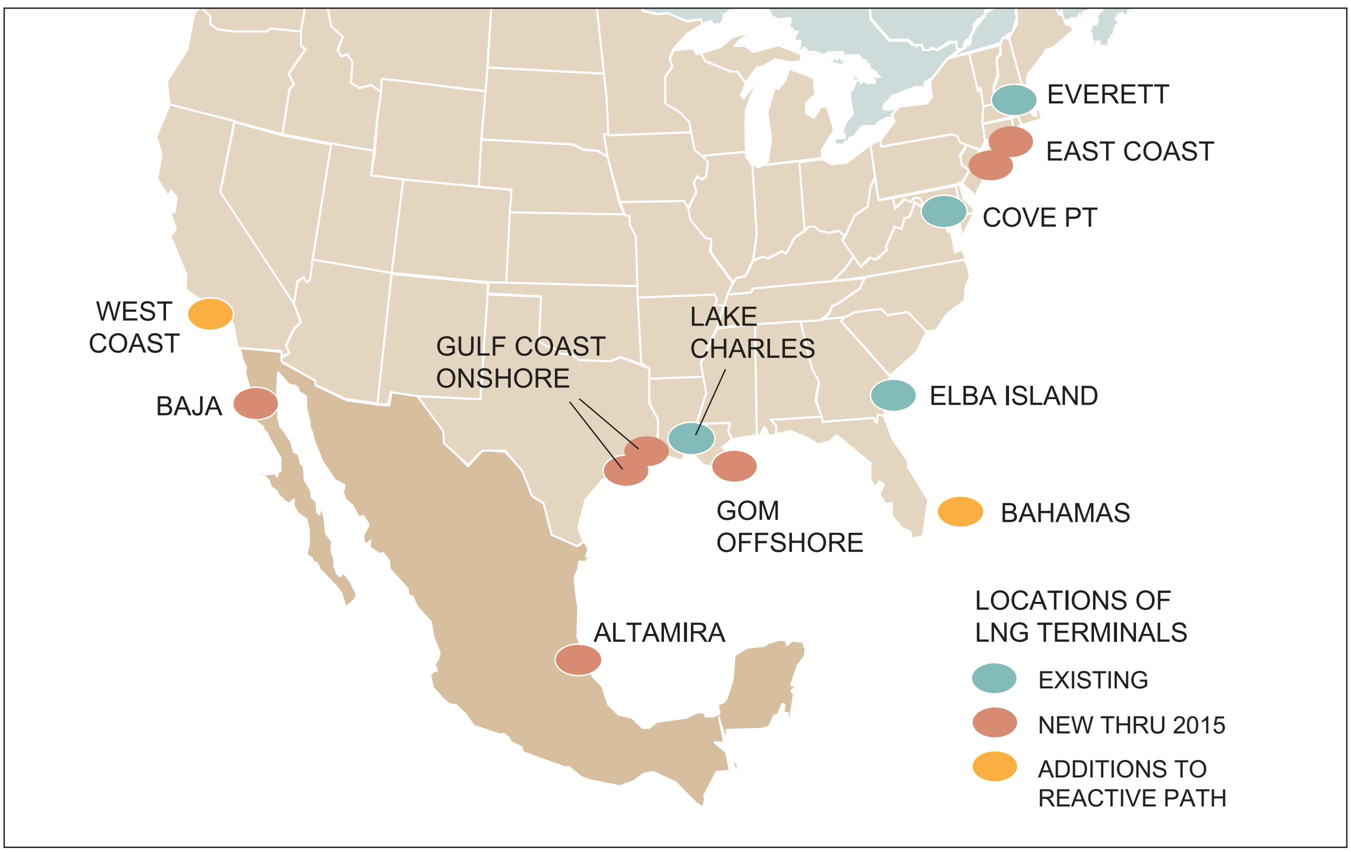


Figure L-21. LNG Terminal Locations – Balanced Future Scenario

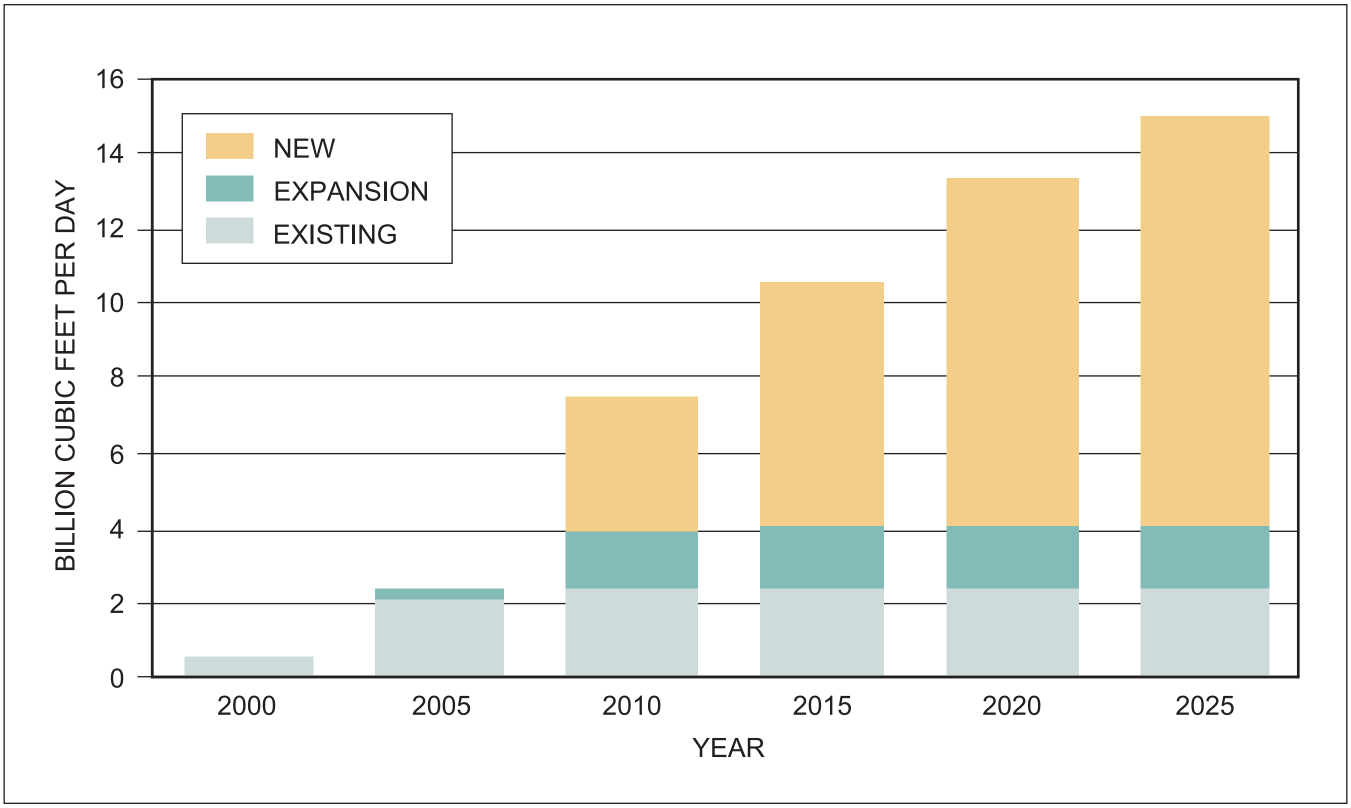


Figure L-22. North American LNG Imports – Balanced Future Scenario

- New Terminals
  + 2007-2010: **6** Total
    - Gulf of Mexico #1 & #2 (2007, 2009)
    - Northeast #1 (2009)
    - East Coast (Altamira) Mexico (2007)
    - West Coast (Baja) Mexico (2008)
    - **Florida (Bahamas) (2010)**
  + 2010-202**5**: **3** Total + **6** Expansions
    - Gulf of Mexico #3 (20**11**)
    - Northeast #2 **(2011)**
    - **Florida Expansion (Bahamas) (2012)**
    - Gulf of Mexico #1, #2, & #3 Expansions (20**15**, 20**17**, 20**19**)
    - Northeast #1 Expansion (20**17**)
    - **West Coast (2021)**
    - **Northeast #2 Expansion (2023)**

3. Low Sensitivity Case

The Low Sensitivity case assumes a combination of regulatory delay and successful public opposition to new terminal development. This scenario assumes that the baseline is developed with a total of only two new import terminals (Gulf of Mexico (2007) and Baja (2008)) and one Gulf of Mexico (2016) expansion. The import volumes gradually increase from 600 MMCF/D in 2003 to a peak of over 6 BCF/D by 2025 (see Figure L-23).

Low Sensitivity Assumptions (changes from Reactive Path highlighted in **bold**)

- Existing terminals are fully utilized by 2007
- Existing Terminal Expansions
  + 2005 - Lake Charles and Elba
  + 2007 - Cove Point
- New Terminals
  + 2007-2010: **2** Total
    - Gulf of Mexico #1 (2007)
    - West Coast (Baja) Mexico (2008)
  + 2010-2020: **1** Expansion
    - Gulf of Mexico #1 (2016)

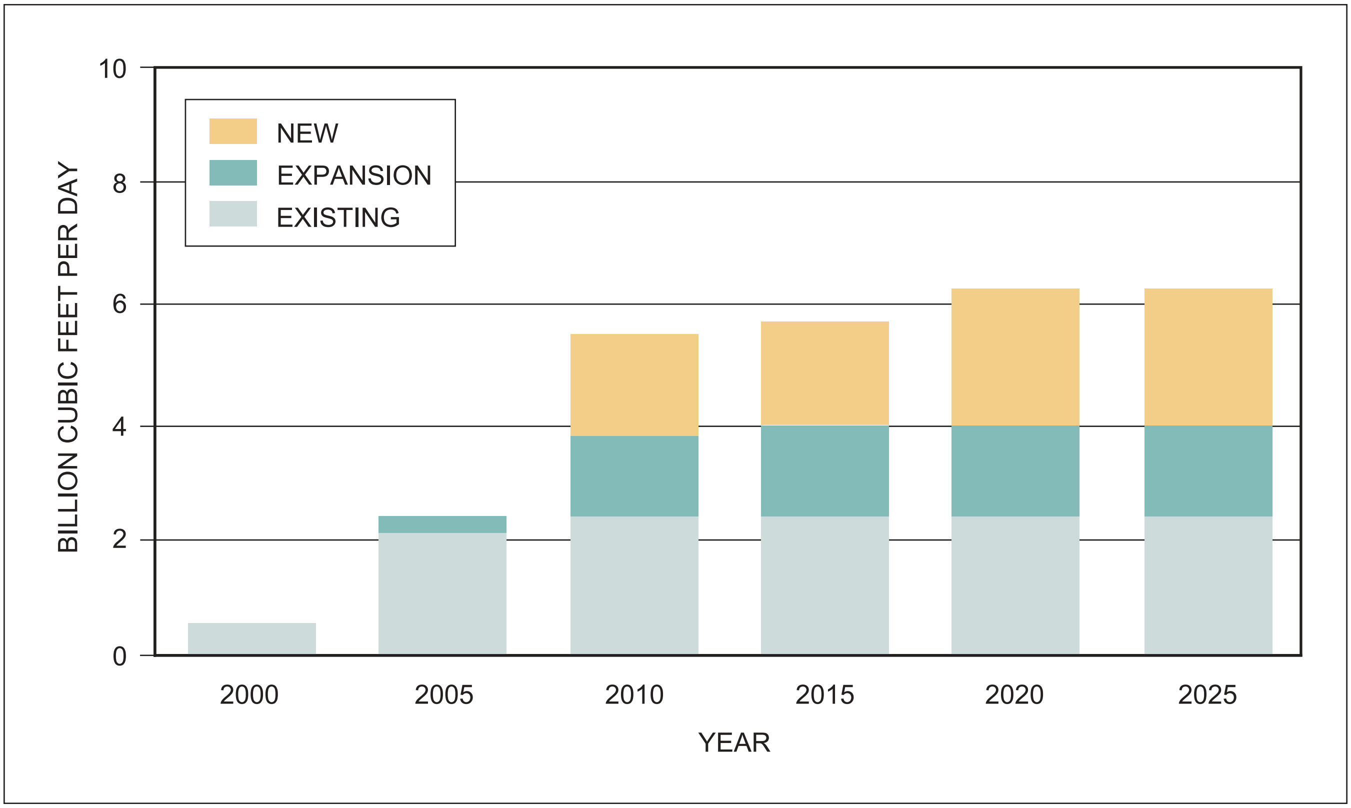


Figure L-23. North American LNG Imports – Low Sensitivity Case

D. Controlling Inputs

The controlling inputs concerning additional LNG imports will be the availability of new LNG supply and the ability for new LNG terminals to be permitted and constructed.

LNG is a global market and the United States will be competing for LNG supply resources. The Reactive Path scenario assumes North America LNG imports will grow to 12.5 BCF/D or about 95 MTA of LNG over a timeframe of about 20 years. To place that in perspective, the global LNG market, which began about 30 years ago and has spread to eleven countries, is presently some 13.5 BCF/D, or approximately 100 MTA. Each of the main market areas, Asia, Europe, and North America are forecast to grow by an average of 6.5% annually. This growth will require over 30 BCF/D of new supply. As each of the three demand areas has significant LNG demand growth potential, there will be significant competition to secure supplies.

E. Case Results

As stated earlier, the volume of imported LNG was hard coded in the model. Therefore, the resulting volume output of the model was equal to the input. Each of the three cases assume that volumes of imported LNG grow, peaking by 2025 as shown in Table L-13.

Figure L-24 illustrates the model results of the volume of LNG imports for the three cases. The increased number of new LNG import terminals in the Reactive Path and Balanced Future scenarios has a significant impact on increased imports. Currently, U.S. LNG imports make up less than one percent of total U.S. natural gas demand. This percentage will increase significantly with the Reactive Path and Balance Future scenarios, resulting in LNG providing 14% and 17%,

	2005	**2010**	**2025**
Reactive Path	2.3	7.3	12.5
Balanced Future	2.3	7.5	15.0
Low Sensitivity	2.3	5.5	6.5

Table L-13. LNG Import Assumptions (Billion Cubic Feet per Day)

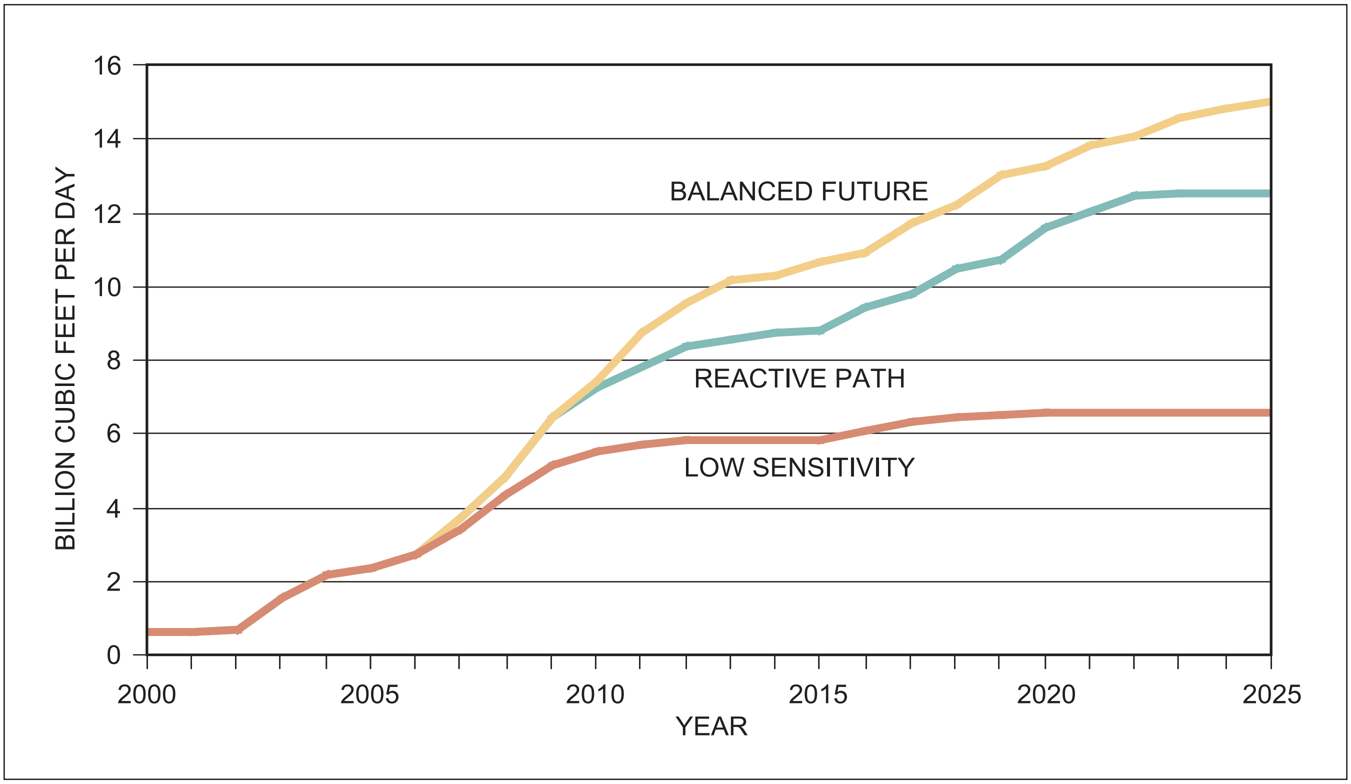


Figure L-24. North American LNG Imports Cases

respectively, of the U.S. supply of natural gas by 2025. The Low Sensitivity case, while not as robust, will still result in LNG making up about 8% of U.S. natural gas supply by 2025.

As the amount of LNG imports is increased in all three scenarios, each has an effect on price. Figure L-25 shows the price variance of the Balanced Future (higher LNG imports) and Low Sensitivity (imports about half of the Reactive Path) cases in relation to the Reactive Path. The LNG imports are the same in all three cases through 2007 because the new terminals and associated new LNG supplies are not on line until after 2007. The impact of the different volume of LNG imports is illustrative through the pricing output of the model. The Balanced Future, with additional LNG imports starting in 2010, has a moderate pricing benefit of about 5% over the 2010-2025 timeframe. It is important to note that the Low Sensitivity case (combination of regulatory delay and successful public opposition) has a much more significant impact on long-term price, with price increases of 10-12%. These cases illustrate the significance LNG imports will have in meeting the growing North America demand and the importance of getting new terminals permitted and built in a timely manner.

VII. Issues

This section defines the most pressing foreign and domestic issues facing the industry in meeting the challenge of filling the growing natural gas supply gap in the U.S. Top priorities include the siting of receiving terminals, the permitting process and the timing of new projects and expansions, the availability of shipping capacity, and the interchangeability of LNG with U.S. gas pipeline systems. Section VIII, a summary of recommendations will suggest ways in which regulators and governments, at all levels, can work to facilitate the growth of LNG supplies in the United States.

A. Siting of New LNG Receiving Import Terminals

The LNG Industry is faced with two critical issues concerning development of new LNG receiving terminals in the United States. The first is siting selection; the second is the ability to obtain permits in a timely manner.

The four existing import terminals are located onshore, in both metropolitan and remote locations. New onshore LNG import terminals require three

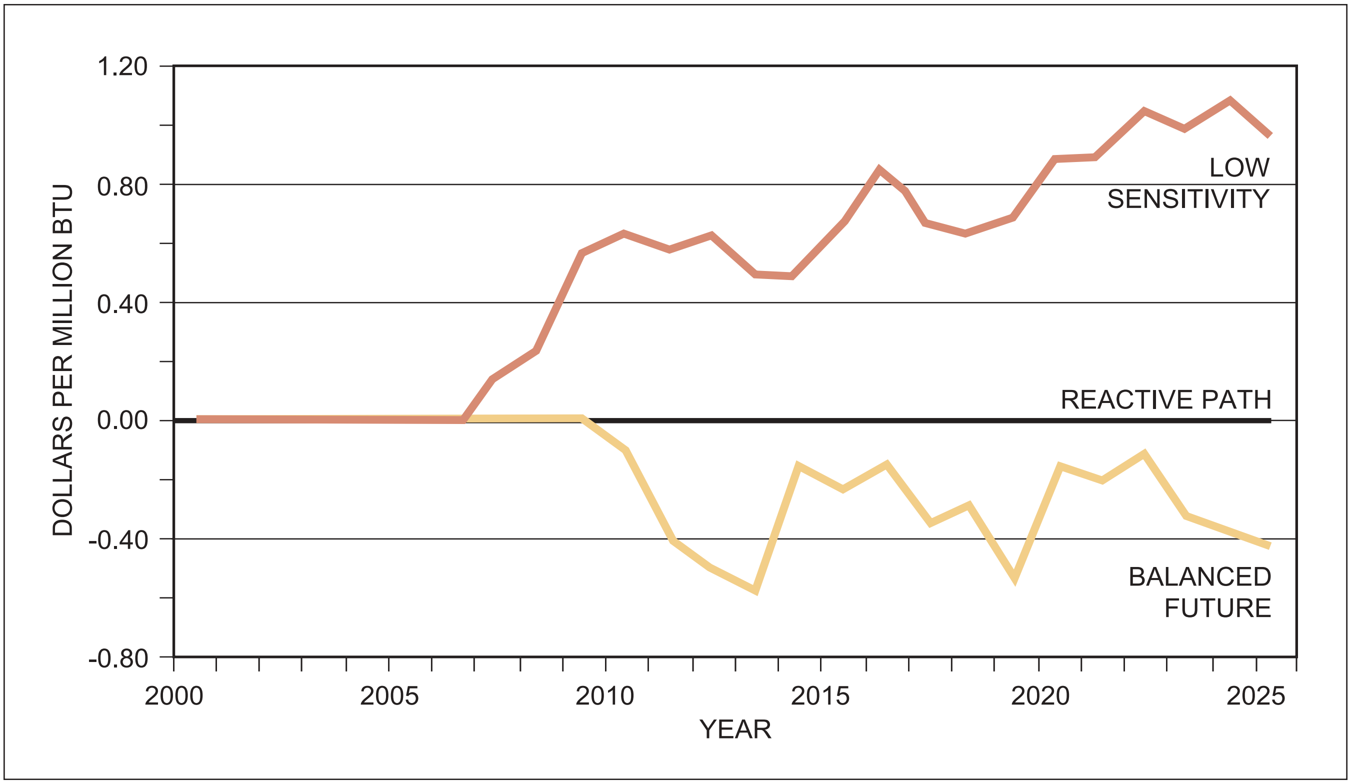


Figure L-25. Price Impact of LNG Import Cases (2002 Dollars)

basic characteristics. They must have sufficient available land (50 to 100+ acres for up to a 1.0 BCF/D facility) adjacent to a deepwater port; the port must have sufficient berthing and room for a turning radius, and there must be access to the port via a deepwater channel. Ideally, the location would be located near large natural gas consuming markets or would have access to large natural gas pipelines.

Advances in technology have also created the possibility of locating an LNG receiving terminal in offshore waters. Depending on the technology employed (for example, Gravity Based Structures or Floating LNG Receiving Terminals), the offshore site must meet certain requirements for water depth and soil conditions.

Onshore or offshore, choosing a siting a location is an arduous task. The United States has a limited number of deepwater ports and even fewer with sufficient land available in the immediate area for an onshore terminal. Of the limited sites available, many are located in developed areas, where public opposition is a concern.

Gravity based offshore LNG receiving terminals can only be placed in locations where critical soil condition criteria are met. This requirement limits the number of potential locations. Floating LNG Receiving Terminals require deeper water depths and typically longer offshore pipelines to connect to shore.

Whether onshore or offshore, LNG receiving import terminals require access to a natural gas pipeline system so that the gas can reach consumers.

B. Regulatory Issues of New LNG Receiving Import Terminals

There are four key regulatory issues facing the timing and acceptance of new LNG receiving terminals in the United States. These issues can be segregated into permitting, streamlining the permitting process, the impact on agency workloads, and additional impacts as a result of limited budget funds.

1. Permitting New LNG Receiving Terminals and Downstream Pipelines

It has been more than 25 years since a permit has been issued for a new LNG receiving terminal in the United States. Obtaining permits for a new LNG terminal will be one of the most crucial steps in developing additional LNG import facilities in the United

States. Securing permits for downstream pipelines, if required, will also be a key hurdle to overcome.

LNG receiving terminals fall under two separate jurisdictional agencies depending on their physical location. Onshore LNG receiving terminals fall under the authority of the Federal Energy Regulatory Commission (FERC). Offshore terminals are under the authority of the United Stated Coast Guard (USCG). Downstream pipelines are under the jurisdiction of FERC if they are interstate pipelines; they come under a state agency if they are intrastate pipelines. While either FERC or the USCG has jurisdictional authority concerning LNG receiving import terminals, each terminal typically requires more than 100 permits from federal, state, and local agencies. Working through the permitting process can be a long and drawn out procedure due to the sheer number of permits required and the number of agencies involved. There is no coordinated, clearly defined process for incorporating all state and local permitting concerns for onshore terminals. As a result, applications for permits may take several years to be processed. Other delays can occur through local opposition. Typically, the permitting process is what allows local constituents opposing the facility to voice their concerns.

As difficult as the permitting process may be, there have been some favorable steps taken by FERC and the U.S. government to advance the development of LNG receiving import terminals. In October 2002, FERC held an industry conference to discuss issues surrounding the open access and regulated market rate requirements for onshore LNG import terminals. FERC reviewed the issues and responded quickly to adopt more market-friendly policies in reviewing applications for LNG receiving terminals under FERC jurisdiction. This response was made in December 2002 in their review of the *Hackberry LNG Terminal, L.L.C.* application. As part of that review, FERC announced a new policy with the aim of removing barriers to the construction of new LNG receiving and regas facilities. Specifically, FERC granted Hackberry the authority to provide terminalling services at negotiated rates, terms, and conditions. Moreover, FERC found that it was not necessary to require Hackberry to offer open access service, or to maintain tariff and rate schedules for its terminalling services on file with FERC. This represents an important change in policy. FERC had previously treated facilities such as these as transportation, rather than supply, entities. Now onshore receiving terminals, while still under FERC jurisdiction, can be proprietary. FERC also no longer requires open access or posted tariffs. This will enable terminals to be built and sized to the corresponding parts of the LNG chain and will improve the prospects for further development of LNG facilities.

The United States government also changed the permitting landscape considerably with the signing in October 2002 of an amendment to the Deepwater Port Act of 1974. The passage of the Maritime Transportation Security Act of 2002 added natural gas, including LNG, to the provisions of the Deepwater Port Act. The significance of this change is that offshore LNG receiving terminals will be treated as Deep Water Ports and as such will come under the jurisdictional authority of the United States Coast Guard (USCG). These ports will be proprietary and will not be required to grant open access or to post tariffs. Another change that may affect the permitting process is the transfer of the USCG to the Office of Homeland Security. As a result, the permitting process for new offshore LNG receiving terminals is undergoing significant review, and new processes and procedures for handling applications are being considered.

2. Streamlining the Permit Process – Agency Interactions

There is a critical need to streamline the permitting process. Both onshore and offshore terminals must secure a significant numbers of permits using a process that involves multiple agencies at the federal, local, and state level, some with overlapping jurisdiction.

Currently, it can take many years to obtain permits for a LNG receiving terminal. Engineering procurement, the first phase of development, typically takes 12 months; construction usually takes roughly 3 years. Because significant capital investment is required for each of these steps (millions of dollars), these investments will not be made until permits are secured. For example, if the permitting process takes 3 years, it can be a total of 7 years before imports can begin. As the engineering and construction timeframes are well defined, the only way to accelerate new imports is to reduce the time required to secure permits. This can be done by streamlining the permitting process and developing interagency agreements to facilitate the permitting process.

FERC has taken on an active role in trying to streamline the federal interagency interactions and has developed a pre-filing process under the National Environment Protection Agency (NEPA). They established a Memorandum of Understanding between cooperating federal agencies to assist with streamlining the environmental side of onshore LNG terminal applications. These steps will effectively allow the FERC regulatory/Environmental Impact Statement process to be completed in less than two years. While this is a positive move forward it only addresses part of the issue. There are many state and local permits that must be acquired before an LNG terminal can be built. These permits require interaction of multiple state and local agencies. Currently there does not exist a "lead agency" with the responsibility of facilitating the actions of these multiple agencies. Due to the lack of guidance, individual agencies can work independent and against each other with the potential to severely impact the timing of processing of permit applications. This can result in delays or the potential of never awarding the required permits.

One of the benefits of the Deepwater Port Amendment was that it established a clearly defined timing process for permit applications. Unfortunately, a number of points remain to be clarified such as: (1) who is responsible for ensuring that a Deepwater Port application is considered in a timely manner, and (2) who determines what is timely. The enabling statute states that the Secretary of the Department of Transportation has been delegated the authority to issue a license to build and operate a deepwater port for receiving and regasifying LNG in areas lying offshore of the United States. With the transfer of USCG from the Transportation Department to Homeland Security, some questions have come up as to the effect of this reassignment on the application review process. This issue is currently in the limelight as the USCG has received two applications (December 2002, January 2003) and they have been forced to address these issues under an accelerated deadline.

3. Agency Workloads

One of the increasing concerns surrounding any application for a new LNG terminal, whether onshore or offshore, is the effect the application will have on agency workloads. With the multiple potential LNG terminals announced, the impact on agency workloads could be very significant. Also, required skill sets may be in short supply as until the recent Hackberry application, it has been more than 25 years since any agency has had to process an LNG receiving terminal import application. These are very detailed applications consisting of multiple documents that contain information prepared from thousands of sources. The application must address the environmental and social impacts, and it normally contains large amounts of technical information. An applicant typically spends several months preparing the voluminous documentation required. This information must then be reviewed by agency personnel. Some applications, because of advances in technology, may be unlike anything the agency has ever seen. These issues, together with an increasing number of permit applications, may create a burden that will require the training of additional staff. This increase in the workload may affect federal, state, and local agencies.

4. Budget Funds

Fewer dollars for federal, state, and local agencies mean fewer people to perform the functions each agency is assigned to perform. When added to the workloads of personnel whose numbers are steadily decreasing due to budget constraints, an LNG import terminal permit application can be seen as huge burden and imposition, straining an agency's already limited resources. If the United States wants to increase the amount of natural gas to be supplied via LNG imports, it is important to have budgeted funds in place for proper staffing of these agencies.

C. Public Perception and Acceptance

In the United States, every person has the opportunity to oppose energy infrastructure projects. If the public opposition solidifies against LNG import terminals, the expansion of LNG imports to the U.S. could be delayed or blocked entirely either in specific areas or more broadly. This public empowerment has occurred partly through efforts to develop sound procedures for local and environmental permitting which provide mechanisms for local concerns to be vetted and addressed. Public empowerment also occurs through the U.S. legal system, which enables citizens to delay projects to a point that they are no longer economically viable.

Unfortunately, this system enables rejection of individual infrastructure projects on narrow grounds without due consideration of larger related issues such as how the nation is to meet its energy needs and at what price. For example, an area or region with growing natural gas consumption could reject LNG import infrastructure and also reject additional pipeline infrastructure. The protection of local interests without regard to larger issues has come to be known as "Not In

My BackYard" or NIMBY syndrome. NIMBY is particularly strong in the United States.

Concerns and misperceptions about safety and reliability complicate the public acceptance of LNG. LNG has not been used widely in the United States, and the physical properties and dangers of this cryogenic liquid are not easy to understand. Indicators about the public acceptance of LNG are mixed. The U.S. has over 50 small-scale facilities that liquefy and store LNG and that operate without any great public opposition (an additional 50 facilities use LNG for gas storage, vehicular fuel, or other niche markets). At Cove Point, Maryland, the community raised a number of concerns when the facility sought to re-open as an LNG import terminal, but these concerns were addressed and the facility reopened in August 2003. In Massachusetts, the Everett LNG import terminal, which requires LNG ships to pass through Boston harbor, closed briefly after the September 11, 2001 terrorist attacks due to concern that a LNG ship could be a terrorist target. A panel of experts determined that because of the properties of LNG and the safety standards of the industry, LNG infrastructure was not a likely terrorist target. According to a report prepared by Project Technical Liaison Associates (PTL), a firm that specializes in LNG security issues[3] "LNG shore facilities are sited to very stringent design and construction codes and standards. These codes require that 'worst case' accident scenarios be used in the siting and design of these facilities. Terrorist acts would result in spills that are very similar to these worst-case scenarios. Therefore, the design of the facilities generally will accommodate most terrorist type acts and minimize any risk to the public."

To summarize, public perception and acceptance of LNG import terminals appears mixed and is not yet fully known. Public concerns largely reflect misunderstandings about the safety of LNG, which points to a need for better education and public information. Without public acceptance, it will not be possible to build additional LNG import terminals in the United States.

D. Geopolitics and Diversification of Supply

In the past, the United States was able to supply all the natural gas it consumed from a combination of domestic production and imports from Canada and, at times, Mexico. This relative self-sufficiency in supply has also made it possible for the U.S. to exclude exploration for and production of oil and gas resources on vast tracts of federal lands both onshore and offshore. However, given the increasing demand for natural gas and the maturation of the North American resource base, this self-sufficiency is no longer possible. Although U.S. natural gas resources are nowhere near depleted, the country must re-examine the way it supplies its increasing appetite for this fuel. The U.S. can continue to increase its use of natural gas, but to do so will require new government policies and private initiatives.

The world's natural gas reserves are sufficient to meet worldwide demand for LNG well into the 21st century. Currently, about 6% of the natural gas consumed in the world is delivered as LNG; this level is expected to grow at a rate of over 6% annually as more countries seek to develop their stranded gas reserves. While the U.S. demand for LNG is projected to increase more rapidly than the worldwide demand, even under the Balanced Future forecast in this study, imported LNG will only account for about 16% of the U.S. supply in 2025.

Moreover, based on the history of the reliability of the LNG business, the security risk associated with sourcing such a small portion of the overall U.S. supply with LNG is extremely low. In fact, over the forty-plus years of experience with LNG there are few examples of long-term LNG deliveries not being made within the commitments of the underlying contracts. Even when producing countries experienced periods of conflict, deliveries often continued. The most recent of these rare occurrences was the shutdown of production operations at the Arun LNG facility in 2001. Civil strife in the vicinity of the plant led to a temporary shutdown of operations. Interestingly, deliveries to the affected Japanese markets were replaced by spot cargoes from other LNG liquefaction plants. Once production resumed at Arun, it has continued without interruption even though political instability in the region remains. Likewise, the largest LNG producing country in the world, Algeria, has struggled for well over ten years with internal conflict, yet deliveries of both natural gas and LNG to European and U.S. buyers have been largely unaffected.

The reason for such reliability in the face of internal turmoil lies in the structure of the LNG business and

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3 Lewis, James P., McClain, Sheila A., Project Technical Liaison Associates (PTL), "LNG Security: Reality and Practical Approaches," LNG: Economics & Technical Conference, January 2003.

its potential effect on the host nation. LNG projects are massive undertakings. Typically, the host country holds a majority interest in the project through its national oil company. Any disruption of operations will seriously affect the country's finances, credit rating, and balance of international payments position. Likewise, the private project sponsors will not undertake the risks in countries considered too unstable to support the development. Since LNG supply projects must be anchored by dedicated, long-term sales contracts with large, stable, risk-adverse customers, curtailment of deliveries would have serious commercial implications for any supplier who came to be seen as unreliable. Clearly, there is a strong incentive for all parties to see that LNG facilities are utilized as intended.

Still, if experience indicates that the risk of interruption of supply may be small, the commercial, operational, and country risks associated with the importation of LNG are, nevertheless, not the same as for domestically produced supplies. But this does not mean that they cannot be managed, and one way to do that is through diversification. The world LNG trade has developed and is expected to continue growing in a way that will make such diversification easier to achieve. Multiple supply opportunities either exist or have been announced. These opportunities give buyers a range of suppliers to buy from. And there is a high probability that more LNG supplies will be developed as more countries with stranded reserves attempt to find a way to market their gas. Some forecasts even call for a net oversupply before the end of the decade. In addition, LNG projects are dispersed throughout the world (see Figure L-11 in Section IV). While the largest known undeveloped reserves are located in Russia and Qatar, there remain many prospective regions around the world where yet undiscovered reserves may be found. As demonstrated by the Arun situation, even if an interruption occurs, the flexibility of the LNG market allows for some quantities of short-term LNG to be delivered to cover shortfalls in deliveries from a long-term supplier. Therefore, given these considerations, it is reasonable to conclude that the U.S. can expect to import LNG under reliable, long-term contracts with a risk profile not too dissimilar from domestic sources.

E. Homeland Security

While safety issues are addressed in other portions of this document and include many aspects of security, the September 11, 2001 terrorist attacks brought security issues to the forefront. Concerns about the potential for terrorists to use LNG as a weapon surfaced in Boston in late September 2001. Coast Guard efforts supported by other agencies (including an interagency team of technical and security experts mobilized by the U.S. Department of Energy), quickly addressed the concerns raised by local authorities. This effort and other studies concluded that LNG lacked the physical and chemical characteristics that would allow it to be used as a terrorist weapon and that the robust design characteristics of tankers and shore based storage render LNG an unlikely target for terrorists. Additional studies separately sponsored by FERC, DOE, and industry participants are being carried out in order to further advance the understanding of credible scenarios in which LNG may be released and ignited.

F. Shipping – Aging LNG Fleet

With its almost 40-year history, a question that may arise is: What is the average useful life of an LNG ship? The life of most wet bulk tankers is about 20 years. LNG ships, because of the need to ensure high reliability and availability, have a longer life. The oldest ship in the LNG fleet is the 38-year old Cinderella, built in 1965. It is still active in the Mediterranean delivering LNG to Spain. As shown in Figure L-26, nearly 25% of the fleet is more than 25 years old. Many people in the industry believe the useful LNG ship life is at least 30 years and some say 40 years or more. The LNG fleet history to date offers no guidance. As shown in Table L-14, only seven LNG tankers have been retired and scrapped. All but one was less than 20 years old when scrapped. However the vessels were not scrapped due to any structural concerns. The first six were scrapped during the 1980s because of excess shipping capacity at that time. The seventh vessel, the Methane Princess, was also scrapped mainly due to small size. When scrapped, the Methane Princess was 33 years old. Assuming a 40-year life, only six LNG ships will need to be replaced by 2010. The aging of the LNG fleet will become a more important issue during the next decade. Again, assuming a 40-year life, 23 ships will need to be replaced by 2015 and 50 by 2020.

G. LNG Interchangeability

Since LNG is produced from a variety of gas reserves throughout the world, there is variation in the composition of the natural gas. A key consideration for importers of LNG is the degree to which the regasified

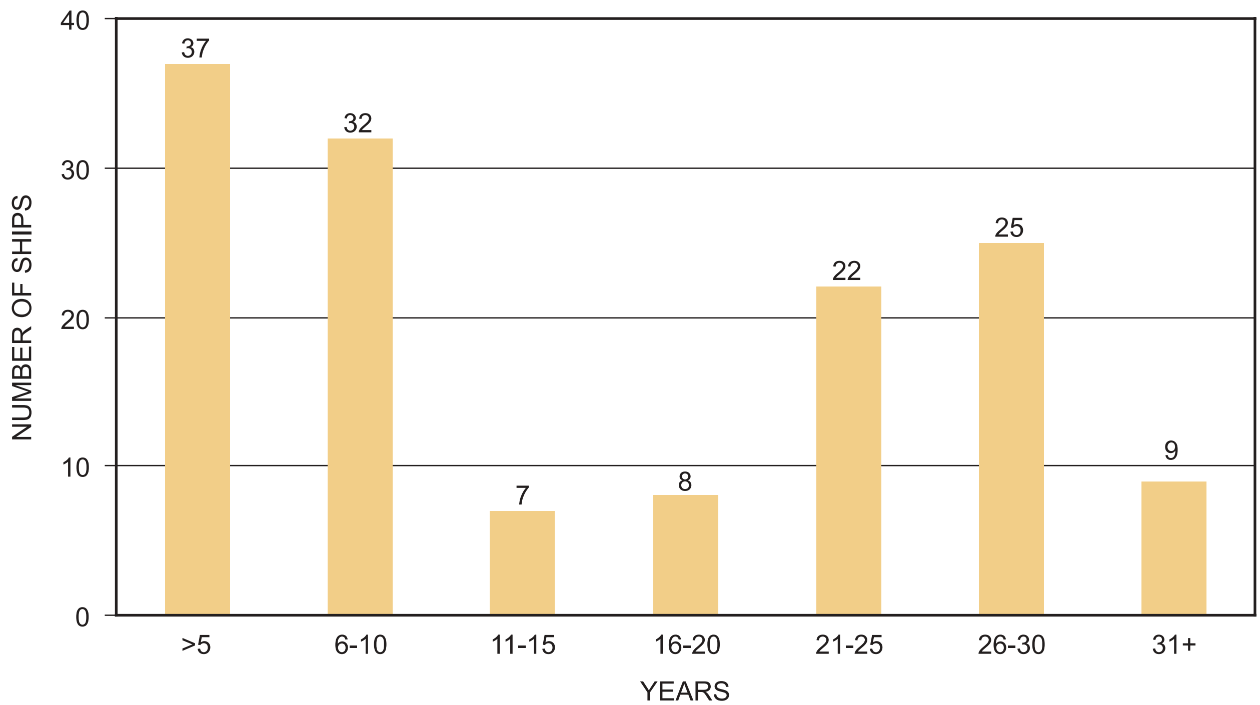

Figure L-26. Current LNG Fleet Age Profile

LNG is "interchangeable" with gas from existing pipelines. Two gases are said to be interchangeable when they can be substituted under the same conditions without affecting the performance of the gas burner.

The introduction of some sources of LNG is a concern to pipeline operators and utilities if the regasified LNG is not interchangeable with domestic pipeline gas. The potential consequences of some sources of LNG include the formation of unsafe levels of carbon monoxide in the exhaust gas formation of gas-fired appliances, knocking in gas engines that are tuned to burn typical pipeline quality gas, and the need to modify plant equipment for certain process gas users.

The ability of the U.S. market to accept a wide variation in gas composition will result in more supply options for the U.S. gas buyers. Fortunately, there are ways to address interchangeability. It involves an understanding of the underlying issue along with the appropriate preparation and close involvement of all the affected parties. A more complete summary of these issues can be found in Appendix E, "LNG Interchangeability."

Vessel Name	Size	Delivered	Scrapped
Esso Porto Venere	41,000 cm	1970	1984
Ben Franklin	120,130 cm	1975	1984
El Paso Paul Kayser	125,000 cm	1975	1985
El Paso Consolidated	125,000 cm	1977	1985
Methane Progress	27,400 cm	1964	1986
Al Rawdatain	125,000 cm	1976	1987
Methane Princess	27,400 cm	1964	1997

Table L-14. LNG Ship Retirements

VIII. Recommendations

This aggressive outlook for LNG import terminal construction will require streamlined permitting and construction to achieve the projected buildup. Expediting the approval process throughout all agencies (federal, state, and local) is critical to overcome the many obstacles that may surface, including local opposition. Leveraging off the recent positive shifts by FERC (positive changes on regulatory process, active leadership role in recent reactivation of Cove Point and Elba Island, and implementation of memorandums of understanding (MOUs) among federal agencies working together) and changes made to regulatory policies in late 2002 governing both onshore and offshore LNG import terminals, will provide a springboard for impacting positive changes down through the local level. The goal of the following recommendations is to reduce the time required for LNG facility permitting to one year.

Project sponsors face multiple, often competing, state and local reviews. This review process typically results in permitting and project delays. Coordination among federal, state and local agencies can reduce permitting lead-time. This can be done through procedural streamlining via interagency MOUs covering topics such as sharing data and findings, concurrent reviews, and setting of review deadlines.

The recent changes to the Deep Water Port Act outlined a defined timeframe (~12 months after application) for the government to make a ruling concerning the application. This process gives the project sponsor the following choices: (1) if accepted, make a decision to move forward with development; (2) make changes as specified for acceptability; or (3) if not accepted, focus efforts elsewhere. The development of specific time-line requirements for all permits (federal, state, and local) will facilitate development of LNG import terminals.

Agencies must coordinate and streamline permitting activities and clarify positions on new terminal construction and operation

Project sponsors currently face multiple, often-competing state and local reviews that lead to permitting delays. A coordinated effort among federal, state, and local agencies led by FERC would reduce permitting lead-time. Similarly, streamlining the permitting process by sharing data and findings, holding concurrent reviews, and setting review deadlines would provide greater certainty to the overall permitting process. FERC should further clarify its policy statement on new terminals so as to be consistent with corresponding regulations under the Deep Water Port Act, including timing for the NEPA review process and commercial terms and conditions related to capacity rights.

LNG import terminals are expensive and complex projects, costing hundred of millions of dollars. Delays of even a few months increase project costs by tens of millions of dollars. Companies need to have a clearer process so they can accurately estimate the cost of filing a complete application (local, state, and federal) and the lead-time required for a decision. Reducing uncertainty will mean lower costs and will increase the potential for development.

Fund and staff regulatory agencies as levels necessary to meet permitting and regulatory needs in a timely manner

The expected increase in the number of terminal applications will require higher levels of government support (federal, state, and local) to process and avoid delays. Additional agency funding/staffing will also be required once these new terminals become operational, particularly to support the increase in LNG ship traffic.

U.S. governments (federal, state, and local) need to plan and commit additional funds and resources needed for processing permit applications and for administrating the necessary procedures to import LNG.

The number of potential LNG terminals, both onshore and offshore, is increasing. The burden will be made even greater because more applications will be submitted than the number that will actually be developed and placed into operations. Some will not go forward due to opposition, lack of commercial structure, or issues with obtaining the required permits. The permitting application process is a lengthy procedure (one to three years) involving many different agencies. The increase in the numbers of applications will be a drain on the agency workforce unless they are properly staffed. Lack of proper staff will result in delays that will in turn delay the rate at which additional LNG imports will be able to enter the U.S. gas market.

LNG imports have increased over the past and it is likely that several new terminals will become operational this decade. Each of these terminals will entail increased LNG activity and will raise unique security and access issues. There will be an increase in LNG shipping traffic and a need for security, inspections and operational compliance. These demands will put place additional burdens on government agencies such as the United State Coast Guard and others.

Undertake public education surrounding LNG

The federal government should publish an educational document on the safety and security of LNG (terminals and ships).

The public knowledge of LNG is poor, as demonstrated by perceptions of safety and security risks. These perceptions are contributing to the public opposition to new terminal construction and jeopardizing the ability to grow this required supply source. Industry advocacy has begun, but a more aggressive/coordinated effort involving the Department of Energy (DOE) and non-industry third parties is required. Emphasis should focus on understanding, safety, historical performance, and the critical role that LNG can play in the future energy supply.

It is recommended the DOE work with industry organizations (University of Houston Study, GPA LNG Subcommittee, SIGTTO, etc.) and publish information on the safety and security of LNG (terminals and ships). This effort would supplement and not be a substitute for industry-sponsored activities.

Implement natural gas interchangeability standards

Measures of natural gas interchangeability in domestic combustion equipment were developed in the 1950s. The introduction of large volumes of regasified LNG into the U.S. supply mix requires a re-evaluation of appropriate interchangeability measures and selection of standards. FERC and DOE should champion the new standards effort to allow a broader range of LNG imports. This should be conducted with participation from local distribution companies (LDCs), LNG purchasers, process gas users, and original equipment manufacturers. DOE should fund research with these parties in support of this initiative.

LNG industry standards should be reviewed and revised if necessary

In order to promote the highest safety and security standards and maintain the LNG industry's safety record established over the past 40 years of operations, FERC, the United States Coast Guard, and the Department of Transportation should undertake the continuous review and adoption of industry standards for the design and construction of LNG facilities, using internationally proven technologies and best practices.

The LNG industry has grown substantially over time and has incorporated advances and improvements in technology. These advances have been focused on decreasing cost while maintaining the highest level of safety standards in both design and operations. With the increase in the number of U.S. import terminal applications, it is imperative that the U.S. terminals maintain the level of safety experienced by the industry to date.

TRANSMISSION & DISTRIBUTION

TASK GROUP REPORT

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TASK GROUP REPORT

TRANSMISSION, DISTRIBUTION, AND STORAGE INFRASTRUCTURE

For purposes of organization, and in acknowledgement of the differing issues of the major pipeline transmission and distribution market segments, the Transmission & Distribution Task Group (T&D Task Group) has chosen to separately report on the areas of pipeline transmission, distribution and storage. In aggregate, the subsections form a coherent analysis, just as the separate but conjoined efforts of the study's Task Groups (Demand, Supply, and Transmission & Distribution) have been combined into an integrated document.

I. Study Approach

In order to incorporate a wide range of industry expertise, the T&D Task Group was comprised of 26 U.S. and Canadian representatives from the following natural gas industry sectors: pipeline transmission; distribution; storage; marketing, and production. When issues arose outside of the specific participant knowledge areas, experts within the represented companies, as well as firms not directly represented on the panel, were contacted for their views. Care was taken to coordinate with the other Task Groups (Supply and Demand) through liaison members. This liaison approach was also followed with the important ad hoc groups, such as Arctic Gas and LNG Imports. Government representatives included participation by DOE, FERC, and EIA.

The analysis relied upon supply and demand data provided by the other Study groups as well as data from the Energy Information Administration (EIA), the American Gas Association (AGA), the Interstate Natural Gas Association of America (INGAA), and other industry associations. NPC member companies also provided data. Early in the study, the T&D Task Group determined and set the major exogenous variables required for the analysis. Examples of these determinations included: selecting pipeline capacity expansions and newbuilds within the first five years; setting the "lag" or delay between a price signal and the construction of a required pipeline developed subsequent to the first five years; determining the cost differentials for construction (pipeline, storage, and distribution) by region; and estimating the amount of storage required for human needs (residential/small commercial) services.

With regard to the issues facing the T&D Task Group, the model makes economically justified decisions to route natural gas, expand pipeline capacities, and construct new storage facilities. The modeling software consists of a complex nodal (physical flow) structure which is fundamentally based on unit pricing concepts. Decisions to flow gas through existing facilities and/or decisions to build pipelines between nodes, add incremental storage facilities, build additional facilities at the citygate, etc., are "calculated" in the model on a year-by-year basis. The network used in the model incorporates 115 supply/demand nodes and 317 transportation corridors (see Figure T-1). The model will always attempt to utilize existing facilities to their maximum, while at the same time looking for pricing signals that would support facilities expansion either to existing facilities or with greenfield projects.

Model output was then carefully reviewed by the T&D Task Group to search for and correct any anomalies. Once the results of the major scenarios (Reactive Path and Balanced Future) were approved, sensitivities of the Supply and Demand Task Groups (which result

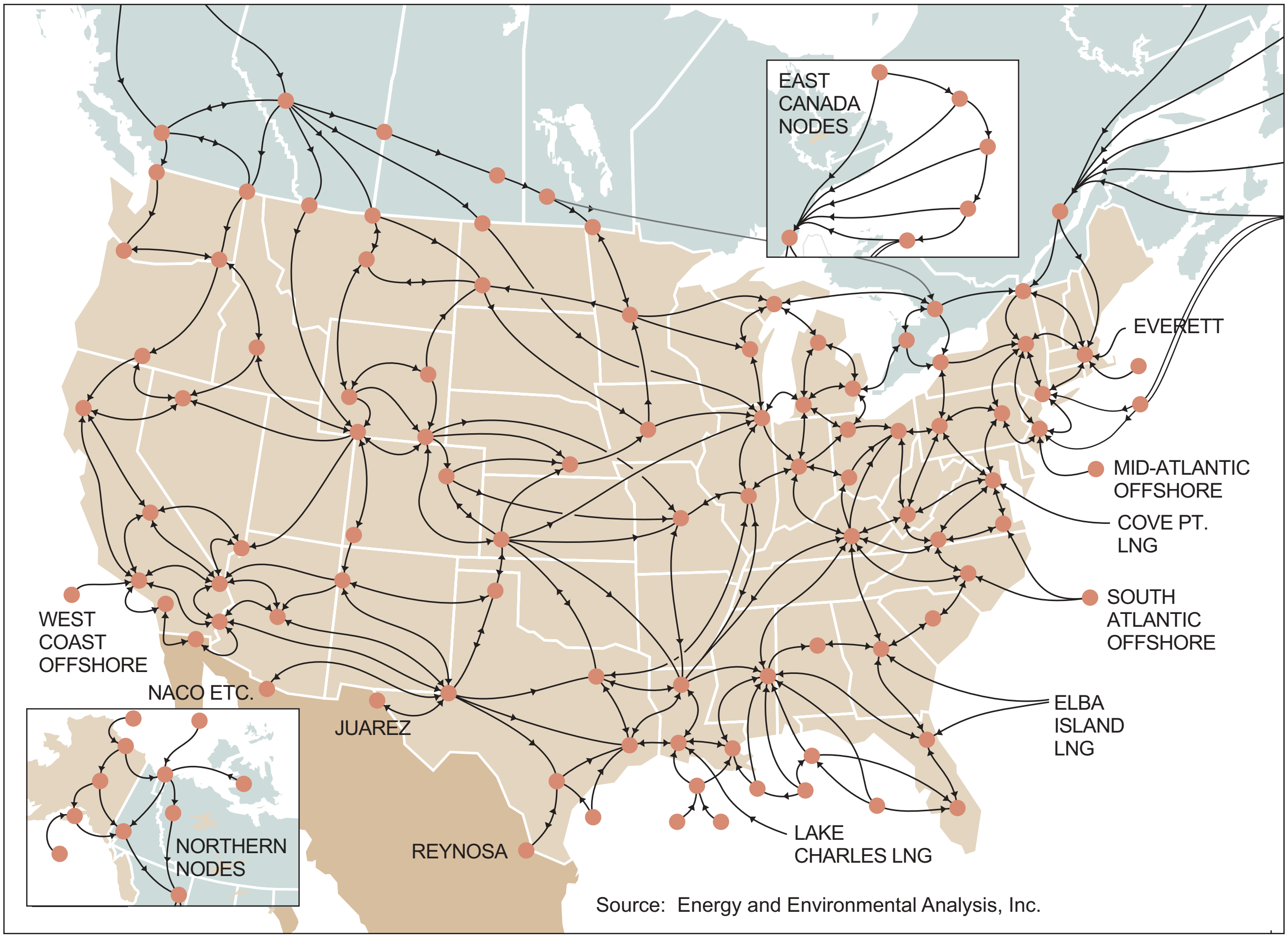

Figure T-1. Supply/Demand Nodes and Transportation Corridors

in differing data inputs to the T&D model) were also reviewed for their impact on T&D results. In addition, the T&D Task Group chose to evaluate its own sensitivities to validate certain stresses upon North American infrastructure.

II. Summary of Results

The study shows that continued expansion of gas transmission, storage, and distribution facilities will be required to meet the future needs of gas consumers and suppliers, but there remains a critical dependency on the existing natural gas infrastructure. Needed expansions or enhancements include increasing the capacity of existing infrastructure, developing pipeline laterals connecting new supply, storage and generation facilities, expanding distribution networks, and building multi-billion dollar pipelines that link Arctic supply regions to the North American grid.

Two scenarios and multiple sensitivities were analyzed with respect to the timing and location of new major supply sources as well as cases related to demand reduction. A status quo approach to natural gas policy yields undesirable outcomes because it discourages economic fuel choice, new supplies from traditional basins and Alaska, and new LNG terminal capacity. The NPC developed two scenarios of future supply and demand that move beyond the status quo. The two scenarios were the Reactive Path and Balanced Future. The Reactive Path scenario assumes continued conflict between natural gas supply and demand policies that support natural gas use, but tend to discourage supply development. This scenario results in continued tightness in supply and demand leading to higher natural gas prices and price volatility over the study period. The Balanced Future scenario builds in the effects of supportive policies for supply development and allows greater flexibility in fuel-switching and fuel choice. This results in a more favorable balance between supply and demand, price projections more in line with alternate fuels, and lower prices for consumers.

The major results for the Balanced Future scenario are summarized as shown below. These results will be compared to the Reactive Path scenario in the Scenarios and Sensitivities section later in this volume. A summary of model input assumptions can be found in Appendix F at the end of this volume.

Pipeline and distribution investments will average $8 billion per year, with an increasing share required to sustain the reliability of existing infrastructure.

Estimated expenditures for new North American transmission pipelines, including sustaining capital, are $2.7 billion/year (2002 dollars) over the study period, from 2004 to 2025. This compares to $3.5 billion/year expended between 1996 and 1999. Peak construction years occur when Arctic pipelines are under construction (2008-2013).

While capital for new infrastructure is decreasing, especially in the later years, sustaining capital is increasing and becoming an increasing percentage of total capital requirements. This is a result of investments for continuing compliance with the Pipeline Safety Improvement Act and the fact that increasing investments are required for an aging infrastructure to assure its safe and reliable operation.

Estimated expenditures for new North American distribution pipelines, including sustaining capital, are $5.3 billion/year (2002 dollars) over the study period, from 2004 to 2025. This is the same as was expended between 1996 and 1999. The successful development of this distribution system infrastructure will depend on several key factors, including:

- Obtaining inter-agency coordination and regulatory certainty in all permitting processes;
- Obtaining access to expansion capital;
- Maintaining the historical levels of reliability and flexibility of natural gas services as gas demand grows and load patterns change;
- Developing mechanisms to foster research and development.

Estimated expenditures for new North American storage facilities, including sustaining capital are $0.4 billion/year (2002 dollars) over the study period from 2004 to 2025. This is slightly larger than that expended between 1996 and 1999. It is important to note that these estimates do not include the cost of base gas, which is projected to be one of the largest components of future storage expenditures. Other observations related to storage infrastructure are:

- Projected growth in weather sensitive demand will require up to 700 billion cubic feet (BCF) of additional capacity by 2025;
- Given that the geologic base for potential storage capacity is highly exploited, new storage facilities may be located further from the markets they serve and may be increasingly expensive to develop.
- A return to normal weather (30-year average) would require utilization rates above those experienced in the 4 years prior to December 2002;
- Demand for gas storage can be as much as 25% higher than normal in a year in which winter weather is significantly colder than normal. North American storage capacity has not been tested by such a winter for many years and, as such, it is likely that current storage capacity will be severely challenged to meet such demands.

Figures T-2 and T-3 show capital expenditures for North America. As can be seen, there is significant volatility in the amount spent on transmission facilities, but expenditures generally decline in the outer years. In addition, as the established infrastructure ages, a significant portion of the ongoing transmission expenditures are used to sustain existing capacity. From 2000 to 2002, sustaining capital is estimated as 21% of total transmission expenditures. By 2020 to 2022, sustaining capital will increase to almost 75%. Sustaining capital for transmission, distribution, and storage is estimated as 21% of total expenditures for 2000-2002. By 2020, sustaining capital for the three segments is projected to be 45% of total expenditures.

Sustaining capital for transmission was calculated on the basis of replacing 700 miles of pipe and 77,000 horsepower of compression each year. This is viewed as a conservative estimate because it is a small fraction of the existing 290,000 miles of pipe and 16,000,000

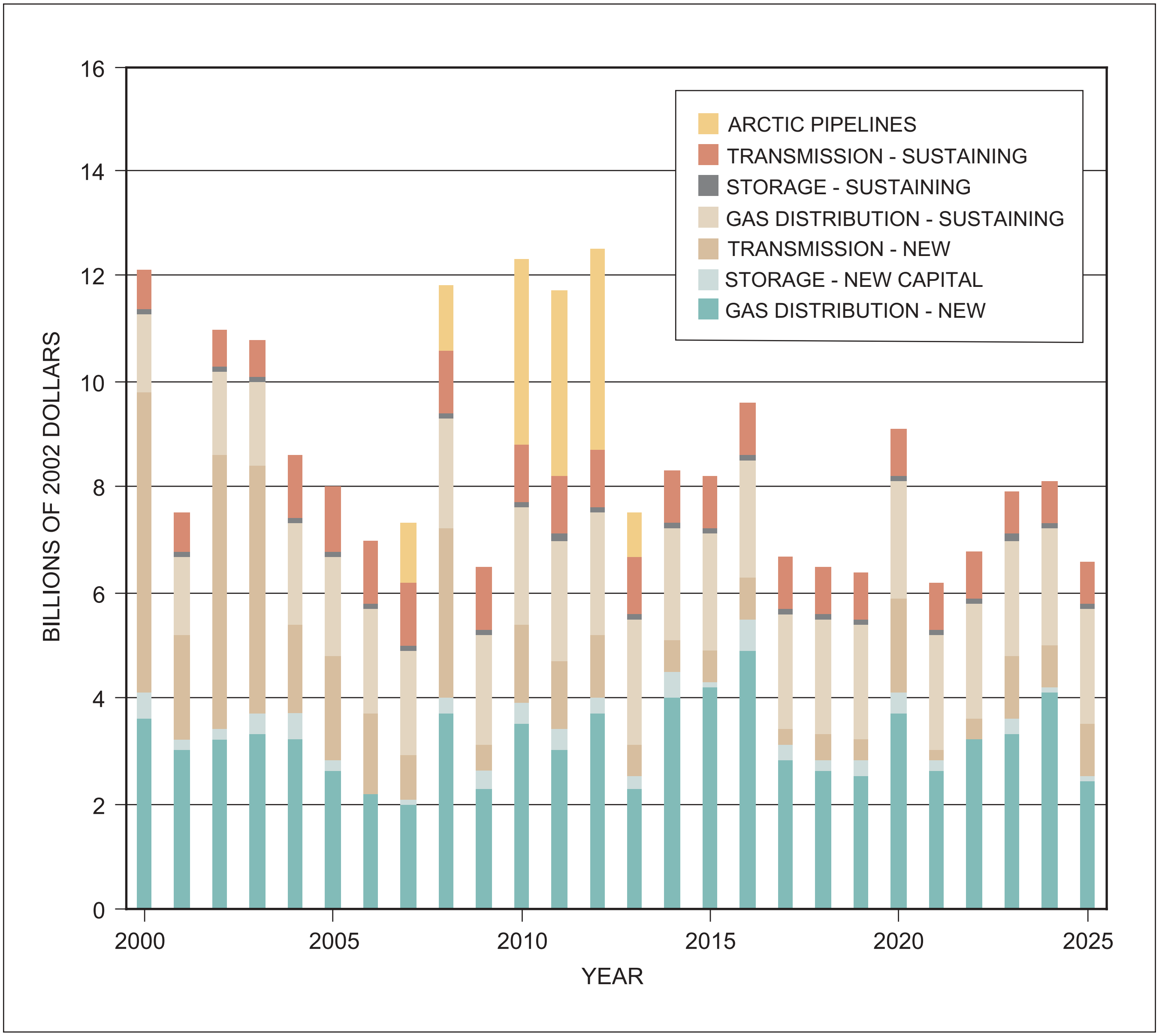

Figure T-2. Detailed North America Capital Expenditures for Transmission, Distribution, and Storage in Balanced Future Scenario

horsepower of compression, much of which is over 40 years old. For instance, if we assumed a 50-year life for pipelines, then the appropriate replacement rate for pipe would be over 5,800 miles per year. The basis for using the lower number is that it better matches the historical level of replacement. Because of the impacts of the Pipeline Safety Improvement Act of 2000, however, we doubled the historical levels for the purposes of the study. At some point in the future, though, the progressive aging of pipelines and compressors will result in a further significant increase in the miles of pipe and horsepower replaced per year.

Regulatory barriers to long-term contracts for transportation and storage impair infrastructure investment.

Pipeline and storage infrastructure developments have generally been financially supported by contracts with a term of ten to twenty years. In a free market, shippers make long-term commitments when they see the need for the service that will be provided. Recently,

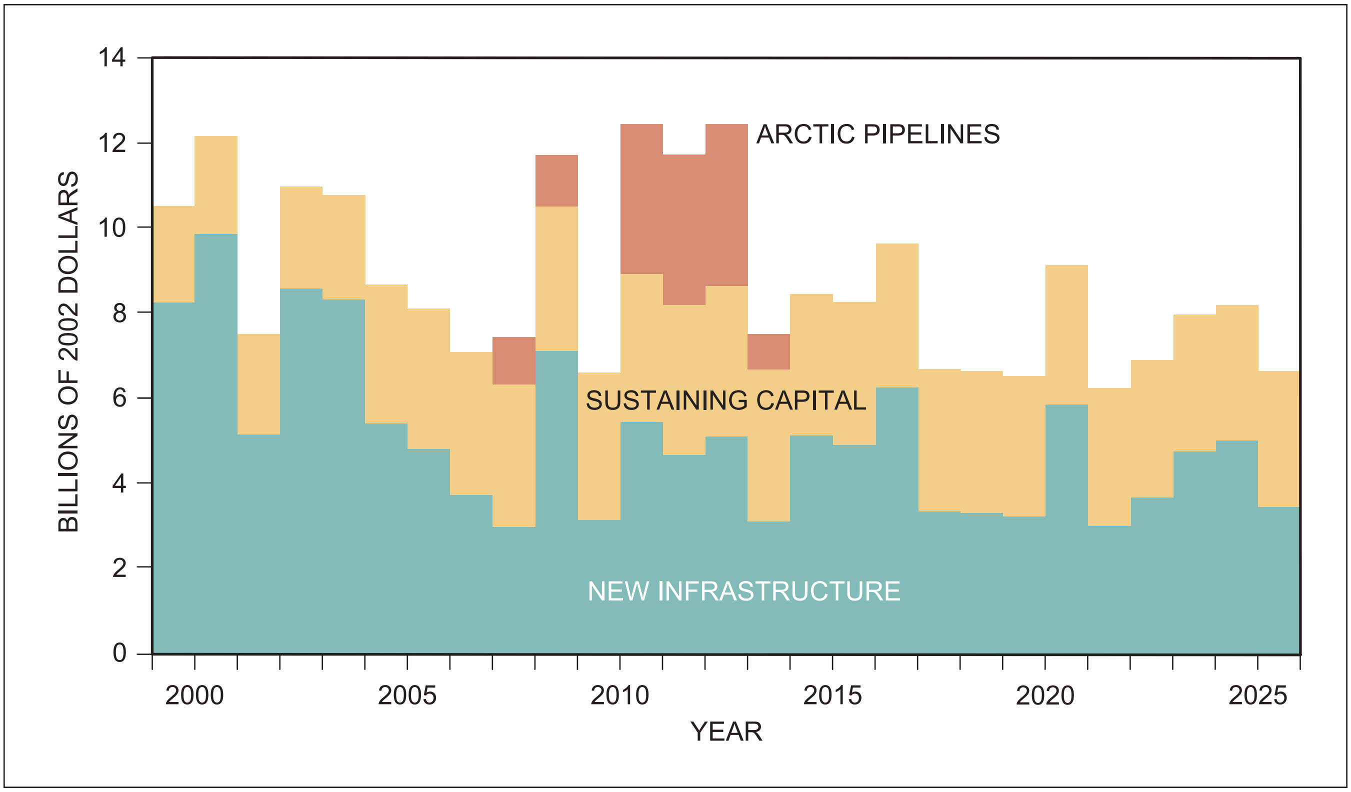

Figure T-3. Total North American Capital Expenditures for Transmission, Distribution, and Storage in Balanced Future Scenario

the average transportation contract term for new/proposed and existing pipeline and storage infrastructure has trended shorter. Much of the trend is the result of market choices, while some is caused by the impact of regulatory policies which may create barriers to choice. When such barriers exist to shippers making long-term commitments, investment in pipeline and storage infrastructure is impacted, as the related revenue stream is viewed as more short-term in nature and less likely to support long-term infrastructure investment.

III. Transmission

The Transmission Subgroup has divided its report into the following major sections: (1) Overview; (2) Future Environment; (3) Challenges to Building and Maintaining the Required Pipeline Transmission Infrastructure; (4) Construction Barriers; and (5) Operation and Maintenance of Existing Infrastructure. While each section may be read on its own, the Transmission Subgroup recommends reading the report in order and in its entirety as the different components are highly interrelated.

A. Overview

The United States' pipeline transmission infrastructure has been developed over a period of eight decades and has provided the nation with reliable access to North American natural gas supply. The infrastructure grew rapidly in World War II to meet the needs of the burgeoning war-time economy and continued its growth during the industrial economic expansion of the 1950s and 1960s. In the 1970s, the pipeline transmission system grew from 255,000 miles to 266,000 miles and expenditures averaged $2.7 billion per year. With a belief in the late 1970s that natural gas was a scarce resource, a decision was made to eliminate natural gas as a fuel source for electric generation. With a major demand component reduced and despite the impacts of a faltering economy and gas supply price deregulation issues, the transmission system grew further in the early 1980s to 271,000 miles, ending 1989 at 276,000 miles. Expenditures during the 1980s were roughly equivalent with the 1970s at the $2.7 billion/year rate. In the 1990s, the relatively low cost and abundance of Canadian production and a corresponding decline of production deliverability from mature U.S. basins led to the creation of significant new cross-border pipeline transmission systems. Average annual expenditures increased to $3.3 billion from 1990 through 1997.

U.S. natural gas consumption has grown significantly from its low point in 1986, rising from 16.2 TCF (44.4 BCF/D) to an estimated 22.6 TCF (61.9 BCF/D) in 2001.[1] During this period, the dominant growth sector was electric generation, including industrial combined heat and power, and the gas transmission grid in the United States grew from 281,000 miles[2] to 285,000 miles.[3] Growth factors for the electric generation segment were an annual average growth of 4.8%, as compared to 0.7%, 2.3%, and 2.0% for the residential, commercial, and industrial sectors respectively. The U.S. grid is a significant part of the North American system of large-diameter pipelines, which is shown on Figure T-4.

1. Historical Background and Statistics

New projects have significantly increased the capacity of the North American transmission grid. For example, the Alliance Pipeline, which runs from Northeastern British Columbia via Alberta to Chicago, has a capacity of 1.6 BCF/D, while Maritimes and Northeast Pipeline, which runs from Nova Scotia to the Boston area, has a capacity of 500 MMCF/D. In the decade from 1990 to 2000,[4] the 12,000 miles of U.S. transmission pipeline added has met demand requirements and improved the efficiency and reliability of North American natural gas markets. Despite the large amount of pipeline transmission growth over that decade, there have still been periods in which the demand for capacity has exceeded its supply. These pipeline capacity constraints have resulted in increased price differentials between upstream supply regions and downstream markets. For example, upstream Western Canadian supply prices were significantly below those of the downstream markets during the 1990s with price differentials sometimes greater than $1.25/MMBtu. As a result, capacity was added, i.e., Alliance Pipeline and the Northern Border expansions to the U.S. Midwest region.

The California supply/demand imbalance during 2000 and 2001 also led to multiple pipeline construction projects including expansions on the Transwestern, El Paso and Kern River pipelines and the conversion of Southern Trails Pipeline from oil to natural gas service. In aggregate, these projects brought over 1.3 BCF/D of new capacity to California.

The one U.S. region that has experienced an ongoing capacity shortfall is the Rocky Mountain supply area. In response, a number of new export projects have been proposed for the region, including Advantage, Western Frontier, Front Range, Cheyenne Plains, Bison, Southern Trails, TransColorado/Silver Canyon, Powder River Basin North, Northwest Pipeline Rockies Expansion, and Ruby. Periodic constraints appear to be the result of a rapid growth in supply that surged ahead of potential shippers' commitments to the long-term pipeline contracts required to facilitate new pipeline construction. Market participants will decide which of the projects will move forward and when.

2. Results from the Study

In the United States, pipeline capacity utilization factors in the Reactive Path scenario are projected to undergo significant changes during the 22-year forecast period:

- The Midcontinent production region (Oklahoma/Kansas) has some of the largest changes in capacity factors, with usage factors on pipelines running from the Midcontinent to the Midwest market region dropping from 94% in 2000 to 54% in 2025.

- The Texas Intrastate market sees major flow realignment, with capacity factors on pipelines running from the Permian Basin to East Texas dropping from 81% at the start of the period to 7%. If Mexican production fails to grow at the rate forecast by SENER, then the steady growth in demand projected over the period may cause exports from the United States to Mexico to increase rather than decrease.

- Capacity factors from Northern Louisiana to the Midwest market areas drop from 75% to 57%, as Arctic supply replaces Gulf Coast gas in the

[1] Energy Information Administration, Natural Gas Table 6.5, Natural Gas Consumption by Sector, 1949-2001.

[2] AGA Gas Facts 2002.

[3] Department of Transportation RSPA 7100.2-1.

[4] Ibid.

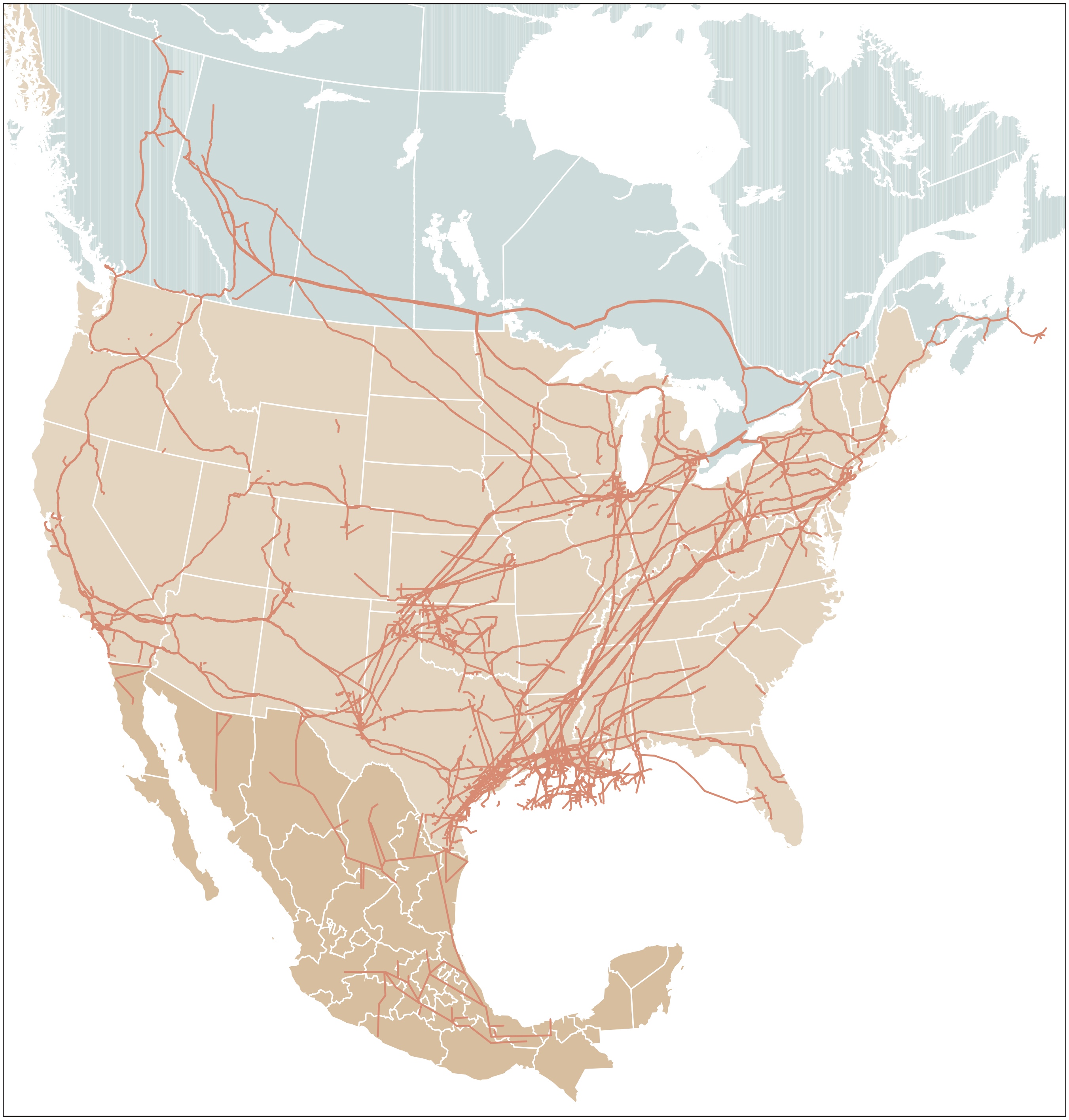

Figure T-4. North American Pipeline Grid (24" Diameter and Greater)

Midwestern energy markets in the latter part of the study period. There is also some reduction in utilization factors in pipelines moving gas from the Gulf Coast to the Mid-Atlantic, assuming LNG landed in East Coast market centers helps to serve demand growth in that region as well as create additional upstream delivery capability through existing pipeline resources.

- The one supply basin showing little excess capacity is the Rocky Mountains. This region shows significant production growth over the study period, growing from 4.4 BCF/D in 2000 to 9.2 BCF/D in 2018 before experiencing a slow decline to 8.7 BCF/D in 2025. As a result of the increase in pipeline transmission capacity prior to 2018 and a subsequent decline in regional production, capacity factors on pipelines leading east of the region have a lower capacity utilization rate in 2025 than in 2000. The capacity factors on pipelines leading to California, however, are above 93% for the entire period.

- In Canada, Western Canada Sedimentary Basin (WCSB) production peaks at 17.9 BCF/D in 2005. Capacity utilization to eastern Canada drops from approximately 94% in 2000 to 81% in 2025. Production in the Maritimes area of Eastern Canada rises to 1.3 BCF/D in 2011, undergoes a gentle decline to approximately 1.0 BCF/D in 2019 and then rises once again to 2.2 BCF/D in 2025.

- The Balanced Future scenario features increased supply access to the Rocky Mountain and Offshore Continental Shelf regions. As a result, flow patterns change from those in the Reactive Path. For example, the Mid-Continent to Midwest capacity factor is 74% in 2025 in the Balanced Future versus 54% in the Reactive Path. Other notable changes in the Balanced Future include over 1.5 BCF/D of production from the Atlantic offshore that flows into East Coast markets, a drop in capacity factors from Canada to the Pacific Northwest from 70-80% to 50-60%, and a drop in west-to-east Canadian long-haul utilization of 81% to 73%.

Pipeline capacity must also be constructed to transport gas from storage to high consumption centers. This is particularly true for storage developed to serve the Mid-Atlantic and New England markets. As noted in the Storage section of this volume, these regions will require an additional 135 BCF of working gas storage by 2025. Because the nearest suitable and undeveloped reservoirs exist in the western portions of Pennsylvania and New York, Eastern Ohio, and Ontario, incremental pipeline capacity of approximately 2.0 BCF/D will have to be constructed to link new storage capacity to the coastal market centers, which include New York City, Boston and Philadelphia.

The incremental pipeline capacity required by 2025 is shown in Figure T-5.

B. Future Environment

1. Throughput Trends

In describing throughput trends, it is illustrative to examine the balance of flows into major market regions. For this purpose, a major market region is defined as one in which consumption exceeds production (New England, Northeast, Mid-Atlantic, South Atlantic, Florida, East South Central, Midwest, Upper Midwest, West North Central, Pacific Northwest, and California).

Between 2000 and 2010, there is an aggregate net consumption growth (consumption minus intra-regional production) of 4.5 BCF/D in the primary market regions. Incremental LNG deliveries into these market regions are projected to account for 3.3 BCF/D of this increased demand. As such, only 1.2 BCF/D of additional long-haul deliveries are needed from net supply to net consumption regions.

Between 2010 and 2020, lower-48 consumption in the major market regions has a further increase of 3.6 BCF/D. In this period, LNG imports into net market areas is projected to increase by 1.5 BCF/D, resulting in a need to increase long-haul transport from traditional supply regions such as the Gulf of Mexico. From 2020 to 2025, net demand in major market regions is projected to remain stable. During this period the net market area increase in consumption is exceeded by projected increases in LNG deliveries. Thus, no additional long-haul capacity development is required.

In Canada, net consumption growth in the major market regions (defined as regions where demand exceeds supply, namely Ontario, Quebec, and Manitoba), is 0.36 BCF/D from 2000 to 2010, or 1.0% per year. Between 2010 and 2020, growth is again projected to be 1.0% per year or 0.4 BCF/D. From 2020 to 2025, the net consumption is projected to decline slightly. Over the study period, there will be no growth in long-haul capacity to eastern Canada as demand growth will be met through enhancement and utilization of existing pipelines.

2. Changes in Flow Patterns (Geographic)

The projected changes in flows across the major North American pipeline corridors are displayed in Figures T-6 (2004 to 2010) and T-7 (2010 to 2020), which are both taken from the Balanced Future scenario. As a result of the decreasing supply in the mature regions of the United States, pipelines connected to these areas will see a gradual decline in throughput. This should be particularly true for the southern sections of pipelines serving the West Texas/Permian Basin to Midwest corridor. The middle/northern sections of these systems (i.e. Kansas, Nebraska, etc.) will be resupplied, however, by growing Rocky Mountain production fed eastward via new pipelines, such as the

Figure T-5. New Pipeline and LNG Capacity Change from 2003 to 2025 in Balanced Future Scenario (Million Cubic Feet Per Day)

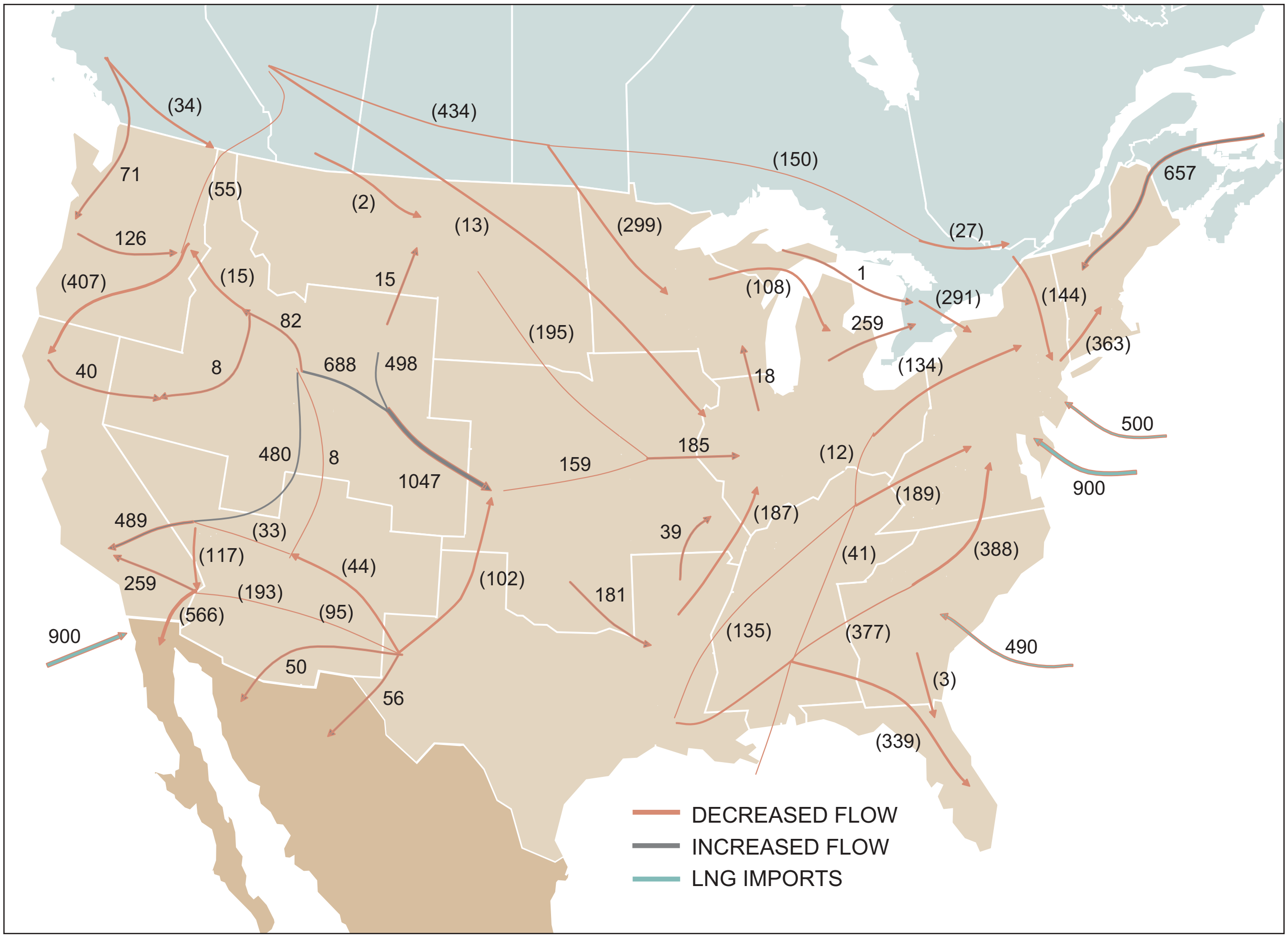

Figure T-6. Flow Change from 2004 to 2010 in Balanced Future Scenario (Million Cubic Feet per Day)

completed Trailblazer expansion, the Cheyenne Plains project, the Advantage proposal, and the Western Frontier proposal.

A significant source of new supply is LNG imports, which rise from less than 0.6 BCF/D in 2000 to more than 7 BCF/D in 2010 and then to 12-15 BCF/D by 2025. Figure T-8 shows the LNG imports projected in the Reactive Path scenario.

When located on the Gulf Coast, these supplies help to maintain throughput in pipelines originating from this region. When located directly in market regions, these facilities will access demand typically with only short-haul infrastructure expansion required. LNG received in the market regions also has the effect of increasing upstream pipeline delivery capability, as gas that previously used the long-haul path will be displaced to potential upstream markets by the LNG received downstream.

As mentioned above, production from the Western Canada Sedimentary Basin (WCSB) peaks in 2005, and then undergoes a long-term decline to 2025, when production drops to 14.3 BCF/D. Part of the production decline is replaced by Arctic gas from Mackenzie Delta and Alaska. The first flow from Mackenzie Delta into Alberta is expected in 2009 at 1.0 BCF/D, increasing to 1.5 BCF/D in 2016. The Alaska production is expected to begin in 2013 at 2.5 BCF/D and then increase to 4.0 BCF/D for the remainder of the forecast period. The combined Arctic flows more than offsets the expected decline in Western Canadian production in the early part of the study. To accommodate these changes in supply, however, major new pipeline systems will need to be constructed from the frontier regions to interface with existing pipeline infrastructure in northern Alberta.

Additional pipeline capacity will also be required to export Alaska gas from Alberta to U.S. and Canadian

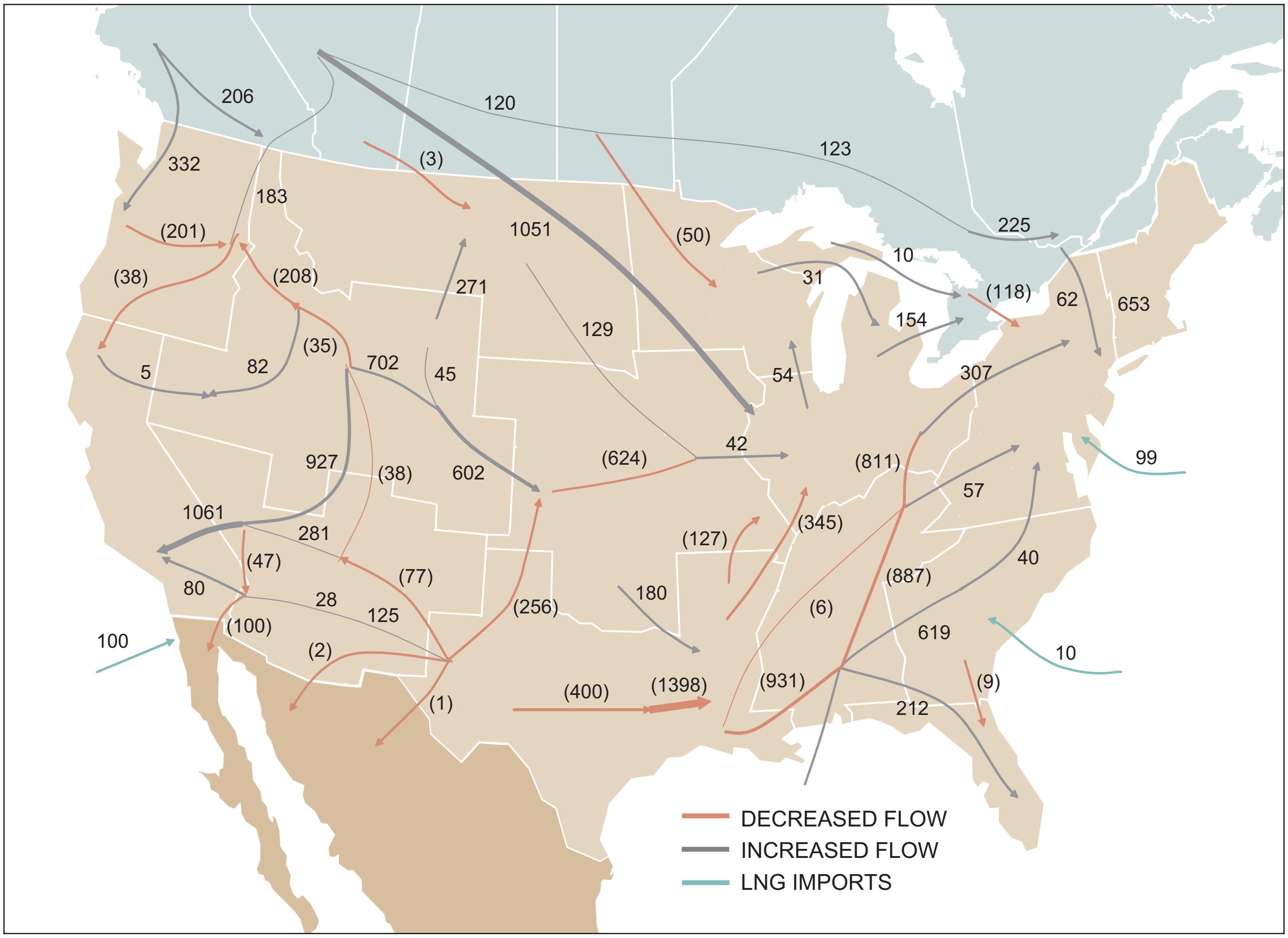

Figure T-7. Flow Change from 2010 to 2020 in Balanced Future Scenario (Million Cubic Feet per Day)

markets. Options for transporting this gas include using existing capacity spared by a decline in WCSB production, expanding existing pipelines, and constructing new pipelines. The NPC analysis suggests that an additional 0.5 to 2.0 BCF/D of new or expansion capacity may be needed to move the gas from Alberta to downstream markets. The amount of export capacity is very sensitive to changes in the western Canada supply/demand balances and could change significantly by the time investment decisions are made regarding Alaska gas.

3. Required/Assumed Infrastructure Additions (Costs)

Future development costs for long-haul pipeline infrastructure and for connection of the transmission grid to new storage and powerplant facilities are forecast to be slightly below historical levels. The cost to construct the new North American pipeline facilities is expected to average $2.0 billion/year (2002 dollars) over the period to 2025. The projected investments are somewhat front-loaded, with the average for the years 2003 to 2010 expected to be almost $2.3 billion/year. These capital expenditure levels compare to an investment rate of $3.5 billion/year, which occurred between 1996 and 1999. The expected decline in the rate of capacity development results from several factors, including a substantial increase in LNG imports delivered to major market centers and the flow of new supplies into existing pipelines that currently have or are forecast to have spare capacity. Both of these actions promote efficiency by maximizing utilization of existing infrastructure while minimizing the need for new construction.

4. Scenarios and Sensitivities

The two scenarios generated results that were very close in terms of total North American transmission

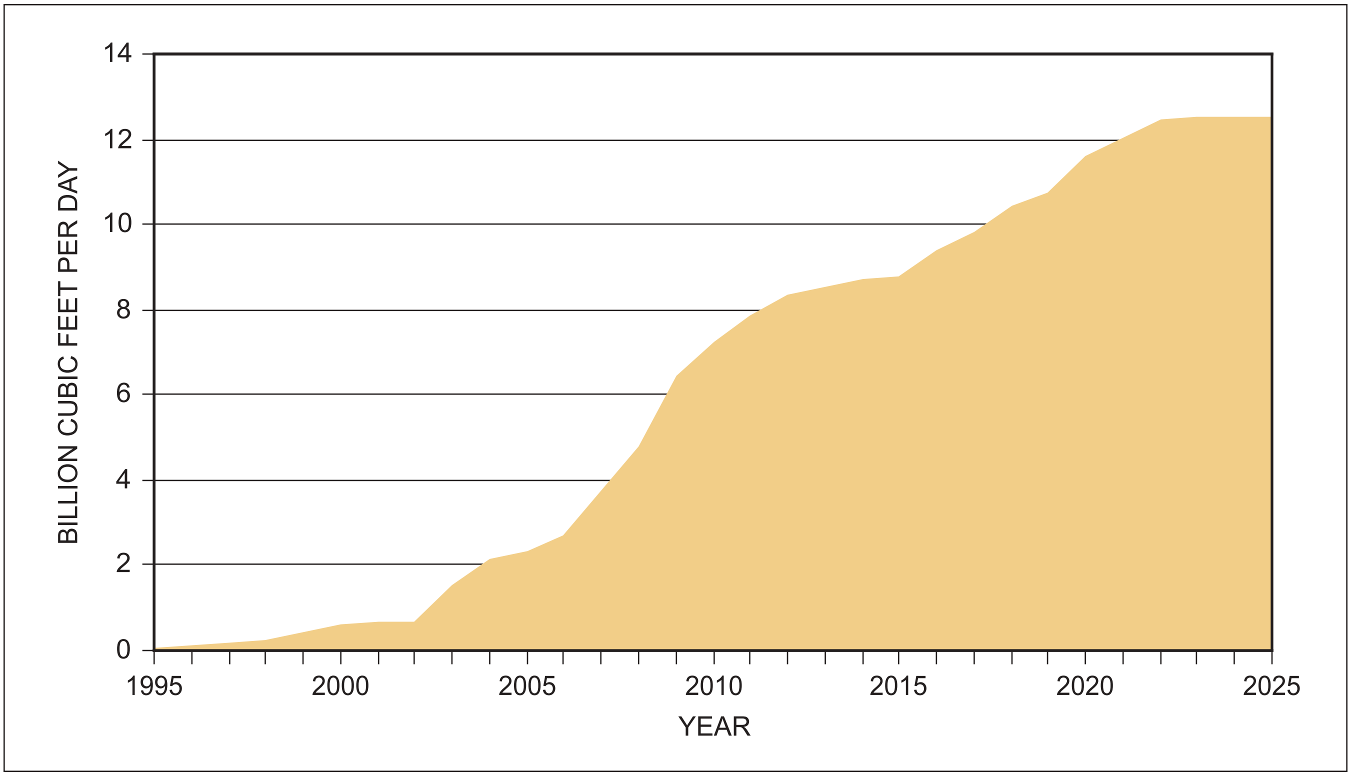

Figure T-8. North American LNG Imports

pipeline miles constructed and expenditures. The Reactive Path projection had 41,200 miles of interstate pipeline constructed over the 2003 to 2025 period at a cost of $1.98 billion/year. In the Balanced Future forecast, the analogous numbers were 43,500 miles and $2.02 billion/year. These cost projections in both cases are below actual expenditures for the last decade, which indicates interstate pipeline development should not be a limiting factor in achieving the necessary supply/demand balance.

The location of the infrastructure costs varied between the two cases, however, with more of the Balanced Future's expenditures occurring in the United States versus Canada. The Balanced Future shows a decline in infrastructure requirements for both eastern and western Canada due to increased production from U.S. areas currently limited by access restrictions. Since the Balanced Future postulates improved access to U.S. domestic resources, more infrastructure is required in the United States. Spending in the United States is thus $77 million per year higher in the Balanced Future while Canadian expenditures decline by $37 million per year.

An important sensitivity is the one in which new LNG import facilities are not approved for construction in the Mid-Atlantic and Northeast regions, causing that LNG to be landed at sites within the Gulf of Mexico. Although no new transmission capacity is required for the Reactive Path, incremental pipeline capacity of approximately 0.3 BCF/D must be built from the Gulf Coast to Florida markets in the Balanced Future scenario to accommodate the incremental LNG proposed in that case. Although little incremental infrastructure is required, this sensitivity results in higher prices in the Mid-Atlantic and Northeast markets than those in the Reactive Path due to a tighter supply/demand balance and pipeline capacity constraints. According to the results of the sensitivity analysis, the delivered costs to New York City are about $0.07/MMBtu higher by 2010. The variance between the two cases widens to $0.30/MMBtu in 2015 and to $0.44 in 2025. The analysis quantifies the higher gas prices associated with not allowing facilities to be built in the region that consumes approximately 8.6 BCF/D or 14% of the current U.S. total. For instance, for a consumption of 8.6 BCF/D, the difference in delivered prices of $0.30/MMBtu in 2015 results in an increased energy cost of $942 million for that year alone.

Another significant impact to gas transmission requirements occurs in the Cold Weather sensitivity. In this forecast, one of the coldest 23-year sequences of weather over the last 70 years was used to determine winter demand. The years used in the forecast were 1956 to 1978, with the temperature patterns in 1956 shifted to 2003, 1957 to 2004, etc. The average price over the full 23-year projection was little changed, as the temperature average for the period was only 3% lower than the temperature pattern used in the Reactive Path and Balanced Future scenarios. The standard deviation of the price, however, was much higher, as the 23-year forecast had episodes of weather that were much colder than normal. Thus, the standard deviation of the average price for the Reactive Path was $0.69/MMBtu whereas the standard deviation for the Cold Weather sensitivity was $0.98/MMBtu. The $0.29/MMBtu variation is sufficient to support the development of additional transmission or storage infrastructure. The effect of colder than normal or warmer than weather on annual prices is shown on Figure T-9.

C. Challenges to Building and Maintaining the Required Transmission Infrastructure

1. Contractual Challenges

During the first seven decades of its history, the natural gas transmission industry's development was underpinned by long-term contracts held by local distribution companies (LDCs). The LDCs ensured the financial integrity of pipeline construction projects by signing 20-year contracts under which pipelines were responsible for the bundled purchase and delivery of the gas to the LDC citygate.

This integral relationship between the transmission and LDC industries began to change in 1983 with the FERC's issuance of Order No. 380, which allowed LDCs to modify their existing gas purchase obligations with pipelines. Further changes occurred in 1986 when FERC, in Order No. 436, adopted open access policies on interstate pipelines, which allowed "shippers" to use a pipeline's capacity to schedule the delivery and receipt of gas. In combination, these Orders gave other parties the ability to compete directly with the pipelines for the gas merchant function.

FERC Order No. 636, adopted in 1992, further changed the competitive environment by essentially eliminating the historical pipeline gas sales function. As a result of this paradigm shift in future regulation, pipelines were restricted to providing transportation and storage services only and could no longer buy or sell natural gas, except for limited operational reasons. This "unbundling" of the transportation and storage

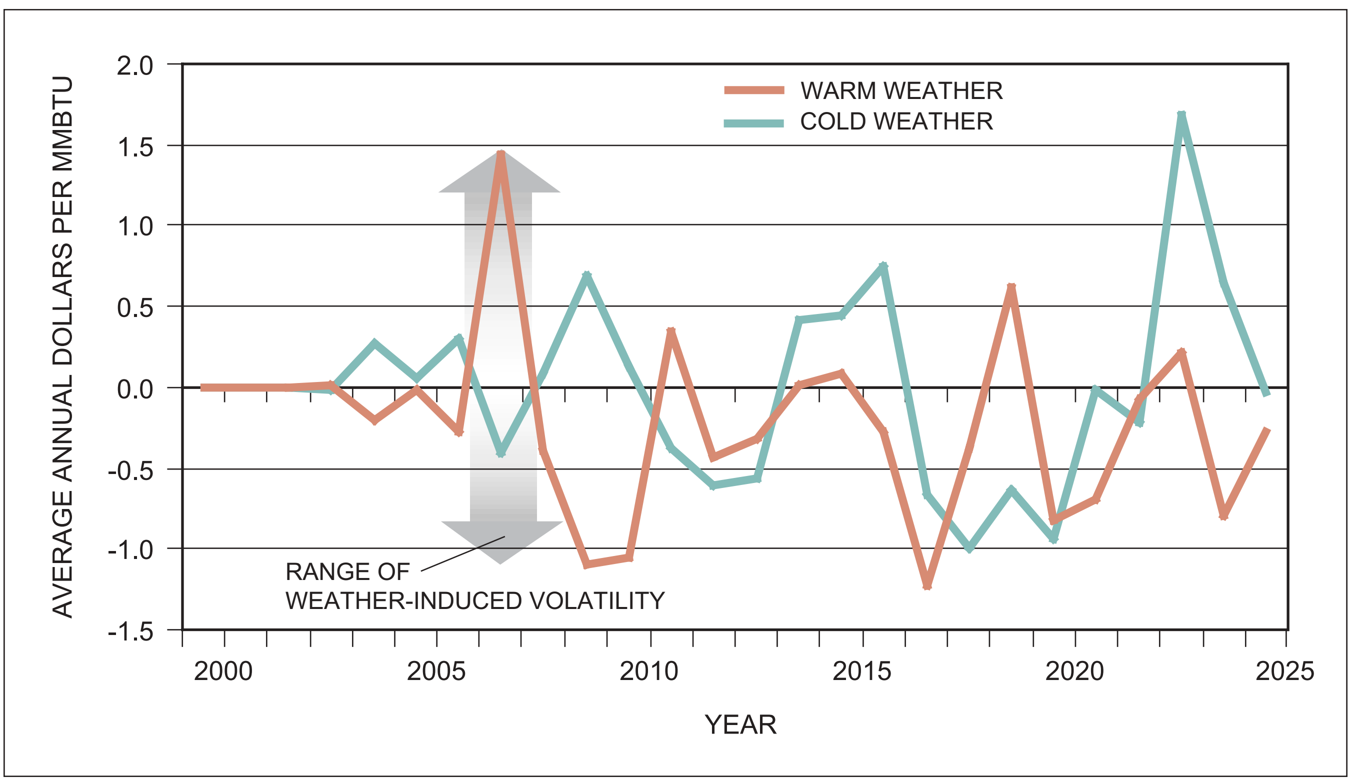

Figure T-9. Weather Sensitivity Minus Balanced Future (at Henry Hub) functions required each upstream supplier and downstream consumer to inherit the responsibility to arrange for the purchase or sale of gas on their own behalf. New tariffs were written and contracts were entered into for unbundled transportation and storage services. In addition, FERC required that a secondary market in transportation and storage services be allowed to develop, wherein shippers could “release” a portion of their contracted capacity to a creditworthy third party for their use, either on a short-term or long-term basis.

Still, the LDCs remained the dominant purchasers of pipeline capacity during the 1980s and 1990s. Their long-term capacity contracts were crucial for the development of new pipelines and the expansion of existing ones. Contracting demographics began to change in the late 1990s with the evolution of the gas marketer business segment, and the unbundling (the separation of transportation and sales functions) of LDCs in many states. By the end of the 1990s, marketers had significantly expanded their role to include a broad portfolio (through the capacity release process or otherwise) of pipeline transmission and storage capacity contracts as well as acting as a managing agent of such resources for others. In their role as managing agent, marketer’s goals were to optimize the use of pipeline and storage assets held by their counter parties, such as LDCs and industrial users, generally reducing these parties’ daily participation in the evolving market. In such business structures, LDCs and end-users “swapped” use and optimization of these assets for ongoing gas management and reduced risk. Correspondingly, marketers saw such arrangements as opportunity and potential upside, as they could use them in a variety of ways which the LDCs and end-users might not.

When LDCs and other major consumers began purchasing gas supplies from marketers, their contracts were generally chosen to be of short duration, i.e. 1-3 years. In such a scenario, marketers often mirrored their risk, becoming short-term holders of pipeline capacity as a means of matching their overall contractual exposures. Some marketers did, however, subscribe to longer-term contracts to facilitate the construction of new infrastructure.

In this unbundled interstate pipeline world, the next market evolution was the unbundling in the 1990s of the sales and transportation functions of many LDCs. This unbundling of LDC services was mandated by state public utility commissions (PUCs) with the expectation that it would increase competition and lower prices to consumers behind the citygate. By the end of the 1990s, unbundling was complete in many states for the industrial gas and electric generation customers and was underway in some states in the residential and commercial sectors. One belief at many PUCs during this time was that unbundling LDCs, with the advent of competition, should no longer enter into long-term pipeline capacity contracts since their share of the future gas sales behind the citygate was uncertain. In fact, many LDCs were prohibited or discouraged from maintaining these contractual commitments.

During this period, producers became increasingly important as subscribers of new supply area pipeline capacity, especially capacity associated with greenfield developments (often referred to as a supply-push scenario). Where it made sense to commit to proposed infrastructure projects to assure their product was available to market, many producers have done such. The producer’s goal was to ensure that they could reliably transport and sell their gas at a liquid, i.e. high volume, sales point where it could receive a market price that was not reduced by a capacity constraint.

Another subscriber to capacity during the 1990s was the marketing affiliates of interstate pipelines. Although the pipelines could no longer buy and sell gas themselves, they were allowed to have an affiliated company that did so. By the end of the 1990s, market affiliates were subscribing to large amounts of capacity in new transmission projects, particularly where third parties weren’t willing to do so. For newly constructed capacity, the FERC required such contracting with their affiliate to be under an “at-risk” condition to the pipeline when it chose to build on this somewhat speculative basis, i.e. without demonstrating long-term contracts from third parties for the proposed capacity.

Today, the recent turmoil in the gas marketing sector has dramatically reduced the number of independent and affiliated marketers as prospective subscribers to existing and/or proposed pipeline transmission capacity. Even where such firms might want to contract for capacity, their current creditworthiness may make them too great a risk for pipelines to consider. With some LDCs still being discouraged or prohibited from entering into longer-term contracts by their PUCs, considerable uncertainty exists regarding the identity of the parties that will contract for unutilized capacity on existing pipelines or who will sign long-term capacity contracts for future pipeline projects.

2. Contracting New Capacity

As stated previously, a key concern for the pipeline transmission industry is the entity that will contract for new and existing pipeline capacity. To give a perspective, the Power Generation, Marketing, Production, and LDC sectors contracted for 91% of the firm transmission capacity subscribed in the United States as of December 2002. The percentage holdings of these sectors have, however, undergone a marked transformation over the last five years. The Marketing sector increased its share of total firm capacity from 13% to 24% over the period. With this business segment in turmoil over the last two years, this change has exacerbated the uncertainty surrounding the identity of companies that will contract for firm transmission capacity in the future.

The Power Generation and Production sectors' pipeline capacity holdings grew at a smaller rate of 5 BCF/D and 2 BCF/D, respectively. The LDC and Industrial sectors, the most important segments of industry growth as recently as ten years ago, were essentially unchanged over the interval. Table T-1 details these findings.

Another marked change within the industry relates to the expiration profile of firm transportation contracts (see Table T-2).

At year-end 2002, 77 trillion Btu per day or 64% of the total firm transportation contracts were set to expire within the following five years. In 1998, the comparable amount was 51%. The 13% increase in expirations between the two five-year periods again indicates a continuing movement to shorter-term commitments. The result is that regulatory practices (prudence reviews and ratemaking) may be inhibiting efficient markets and discouraging the financial incentives to develop and maintain pipeline infrastructure. This information is displayed graphically in Figure T-10.

Given the importance of the Power Generation Sector to growth projections in this study, it is worthwhile to focus on that sector in more detail. The gas fueled power generation capacity increased approximately 128,000 megawatts from 1998 to 2002. This generation consisted of combined-cycle gas turbines (CCGT) installations that generally are intermediate dispatch and tend to operate more than their gas turbine counterparts, which are generally used for hourly electric peaks. If this generation capacity were to have been completely utilized, a significant amount of daily gas transmission capacity would have been required for supply to the plants. In a survey of nationwide contracts, however, firm gas transmission capacity for power generators increased by 13 BCF/D, indicating that participants in this sector chose to contract for less than 100% firm transportation capacity, determining that was within a manageable level of need and risk/exposure. Of the overall capacity contracted by the electric generation industry, utilities directly held

				Share of Total	
	2002	**1998**	**Increase/ (Decrease)**	**2002**	**1998**
Power	18	13	5	15%	12%
Marketer	29	14	15	24%	13%
Producer	12	10	2	10%	9%
LDC	50	50	0	42%	46%
Industrial	4	4	0	3%	4%
Pipeline	6	10	(4)	5%	9%
Other	1	8	(7)	1%	7%
Total	**120**	**109**	**11**	**100%**	**100%**

Table T-1. Firm Transportation Contracts (Billion Cubic Feet per Day)

	2002		1998	
1 Year	27	22%	16	15%
2 Years	42	35%	30	27%
3 Years	58	48%	42	39%
4 Years	66	55%	48	44%
5 Years	77	64%	56	51%
All Remaining	43	36%	53	49%
Total	120	100%	109	100%

Table T-2. Cumulative Firm Contract Expiration Profile (Billion Cubic Feet per Day)

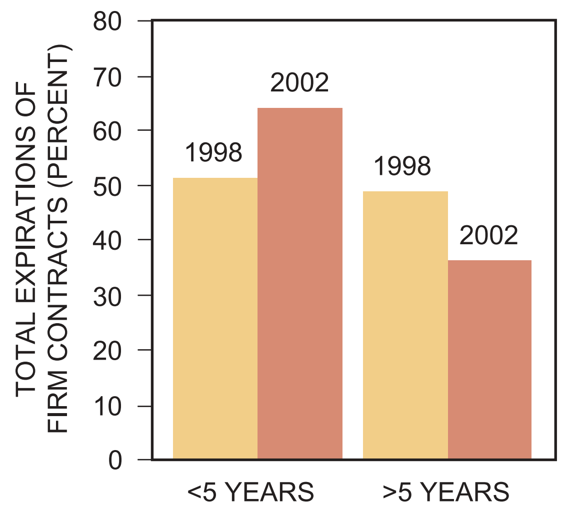

Figure T-10. Firm Contract Expirations

5 BCF/D and marketers, on behalf of merchant generators, held 8 BCF/D. The remainder of needed pipeline transmission capacity was secured by the power sector through either interruptible pipeline capacity and/or release of firm transmission capacity. These data are shown on Table T-3.

The 5 BCF/D of firm transmission capacity contracted by electric utilities during the past 5 years has an average contract term of about 7 years. These firm contracts often reflect durations necessary to cover the short-term, amortized costs of pipeline infrastructure construction to attach new generation facilities, both mainline capacity and lateral construction. Although there was a 62% increase in gas power generation capacity during a relatively short time-span, the expiration profile for this 13 BCF/D of new firm pipeline capacity is widely dispersed across many years.

The 8 BCF/D of firm transmission capacity contracted by the Marketing sector during the last 5 years, on behalf of merchant generators, had a much shorter-term trend, with an average term of 3 years. The expiration profile for the Marketer contracts is thus shorter in duration than those held by the electric utilities by about four years.

At year-end 2002, the Power Generation sector had 334,000 megawatts of total installed gas-fired capacity. Firm transmission capacity contracted by the power generators was 30 BCF/D. The expiration profile of the power sector's entire 30 BCF/D of firm transmission capacity at year-end 2002 (18 BCF/D utilities and 12 BCF/D marketers) is distributed across the next 20

	Year-End 1997	Change 1998-2002	Year-End 2002
Gas Power Capacity (Megawatts)	206,000	128,000	334,000
Contracted Firm Transmission Capacity (BCF/D)			
Utilities	13	5	18
Marketers	4	8	12
Total	**17**	**13**	**30**

Table T-3. Power Sector Gas Transmission Summary years. However, the contracts are skewed in 2003, as the marketers tended to source numerous of these facilities with a short-term orientation/strategy, as can be seen in Figure T-11.

It is important to note, that approximately 190,000 megawatts (57%) of gas power generation capacity at year-end 2002 relies on non-firm gas transmission capacity. These were market choices, as the operators of these facilities have assumed the risk of service interruption by not securing firm contracts. Possible implications are as follows:

- As the utilization rate for these generation plants increase and surplus pipeline capacity declines, gas accessibility using interruptible pipeline capacity will become increasingly problematic.

- During the summer season, increasing power utilization will often conflict with traditional gas storage injections and will strain the pipeline and storage system resources. For example, gas injections may be pushed into only the evening hours and/or more injections may be required earlier or later in the summer season, i.e., in the shoulder months of April, May, and October.

- The current fleet of gas-fired generation – many of which do not have fuel flexibility to consider alternate fuels – and future power development facilities may not be able to depend on immediately available surplus pipeline capacity.

In recent years, several green-field gas transmission pipelines were constructed with the power sector as the primary shippers. These classic demand-pull projects include the Florida Gas and Kern River Expansion pipeline expansions. These pipelines share several unique attributes, such as a diverse customer base of merchant generators, municipal and integrated utilities, firm contract commitments for 10 to 20 years, which matches the financing duration for the new pipeline construction, and their location in markets that have historically utilized firm transportation to supply power generation. The total new capacity for these pipelines is 1.3 BCF/D. Therefore, much of the contracting activity by the Power Generation sector has occurred in the existing pipeline capacity market and is based on the historical pattern of seasonal capacity availability.

Fortunately, the natural gas industry has time to respond to any increased pipeline transmission

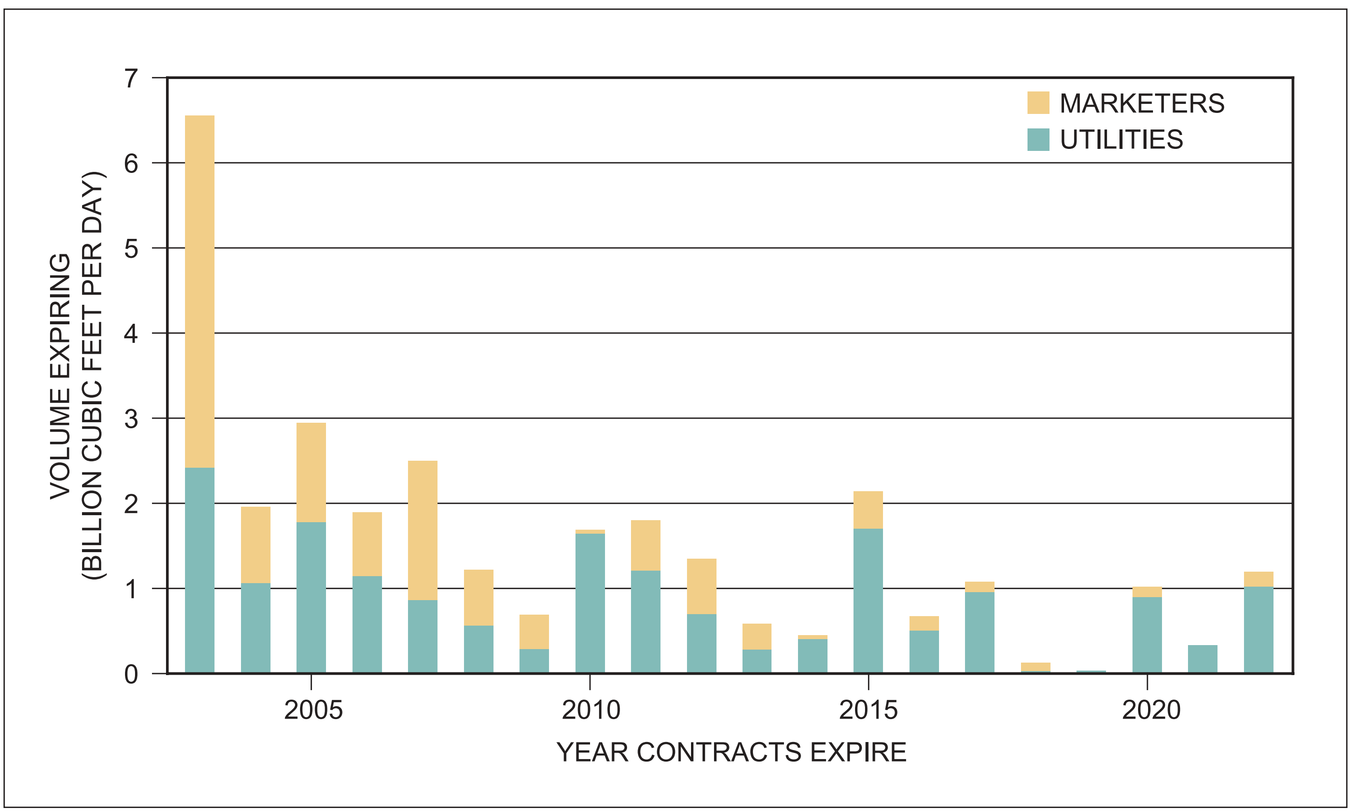

Figure T-11. Firm Contract Expiration by Year and by Shipper Class requirements. The recent, rapid build-up of gas-fired generation has increased generation reserve margins above the required levels in most regions such that little new generation construction is likely to occur over the next few years. Under projected power demand growth in this study, the levels of throughput on long-haul pipelines should increase over time as the new generators are increasingly utilized, but the full potential of their demand and the need for new supporting pipeline infrastructure should not be felt until after 2008. When the Power Generation sector resumes development post 2008, new gas transmission capacity will need to be added. Some new pipeline capacity for the power sector will require firm transportation contracts; these contracts are likely to be similar to those employed for the 13 BCF/D of firm capacity added during the 1998 to 2002 period.

With regard to the Marketing sector, firm pipeline capacity held increased by 15 BCF/D between 1998 and 2002, which doubled their capacity. Marketers held 13% of pipeline capacity in 1998, and by 2002 their share had climbed to 24%. Marketer growth has been driven by several factors including development of non-utility power generation facilities, expansion of merchant trading, and retail deregulation. The contract expiration profile among Marketers reveals their preference for shorter-term contracts than either LDCs or traditional utility Power Generators. As can be seen in Table T-4, contracts expiring during the next 12 months after 1998 represented 41% of the total Marketer capacity. Corresponding values for LDCs and utility Power Generators were only 8% and 9% respectively. By 2002, Marketers continued to hold 37% of their capacity in contracts with 12 month or shorter durations.

A similar trend was observed for the five-year expiration profile. In 1998, 75% of Marketers' firm transportation contracts expired during the succeeding five years. Corresponding values for LDCs and Power Generation were 43% and 38% respectively. By 2002, Marketers still had 71% of their contracts expiring during the next five years. Although overall contracted firm capacity had doubled during this intervening period, Marketers have retained a short-term horizon for their pipeline contracts.

1998	**Marketer**		**LDC**		**Power**	
1 Year or less	6	41%	4	8%	1	9%
2 Years	7	48%	8	17%	2	18%
3 Years	8	57%	16	32%	3	27%
4 Years	10	70%	19	37%	4	28%
5 Years	11	75%	22	43%	5	38%
All Remaining	3	25%	28	57%	8	62%
Total	**14**	**100%**	**50**	**100%**	**13**	**100%**

2002	**Marketer**		**LDC**		**Power**	
1 Year or less	11	37%	9	17%	2	14%
2 Years	13	45%	18	37%	3	19%
3 Years	17	57%	25	50%	5	29%
4 Years	18	62%	29	59%	6	36%
5 Years	21	71%	35	71%	7	41%
All Remaining	8	29%	15	29%	11	59%
Total	**29**	**100%**	**50**	**100%**	**18**	**100%**

Table T-4. Cumulative Firm Contract Expiration Profile (Billion Cubic Feet per Day)

The overall contracting tendencies of Marketers can obscure important trends within different components of the sector. The Marketer sector is, in fact, composed of four major segments as can be readily discerned in Figure T-12, e.g. merchant power marketer, gas marketer, producer marketer, and retail distribution marketer. Each of these segments has been individually analyzed to determine the effect of their contracting trends on the future environment.

Marketers supporting merchant power have grown dramatically during the past five years, adding 8 BCF/D of firm pipeline capacity, about half of the growth in the total Marketer sector. Merchant power marketers held 12 BCF/D of firm pipeline capacity at year-end 2002. However, due to the recent significant overbuild in electric generation capacity, it is unlikely that merchant power marketers will support construction of any incremental pipeline capacity during the next five years. After 2008, when electric reserve margins have contracted and another phase of gas-fired generation construction is expected, then marketers supporting merchant power facilities are expected to play a renewed role in supporting new pipe line infrastructure.

Marketers focused on gas marketing, which includes merchant trading and retail choice programs, have increased firm pipeline capacity holdings by 2 BCF/D during the past five years. This marketer segment held 9 BCF/D of firm pipeline capacity at year-end 2002, but tended to have the shortest-term perspective, as about 55% of the contracts expire within two years. Thus, the pipeline transmission sector cannot depend on these short-term-oriented marketers for construction of new pipeline infrastructure.

Marketers supporting producers held 6 BCF/D of firm pipeline capacity at year-end 2002. In general, marketers supporting producers tend to have longer-term contract durations and have often been the major support for new pipeline infrastructure and capacity additions in the supply regions.

Marketers serving regulated distribution companies are a small segment, with 2 BCF/D of firm pipeline capacity at year-end 2002. This niche segment does not appear likely to support significant new future pipeline capacity development.

Producers, viewed and reported separately from the Producer Marketer segment, held firm transportation

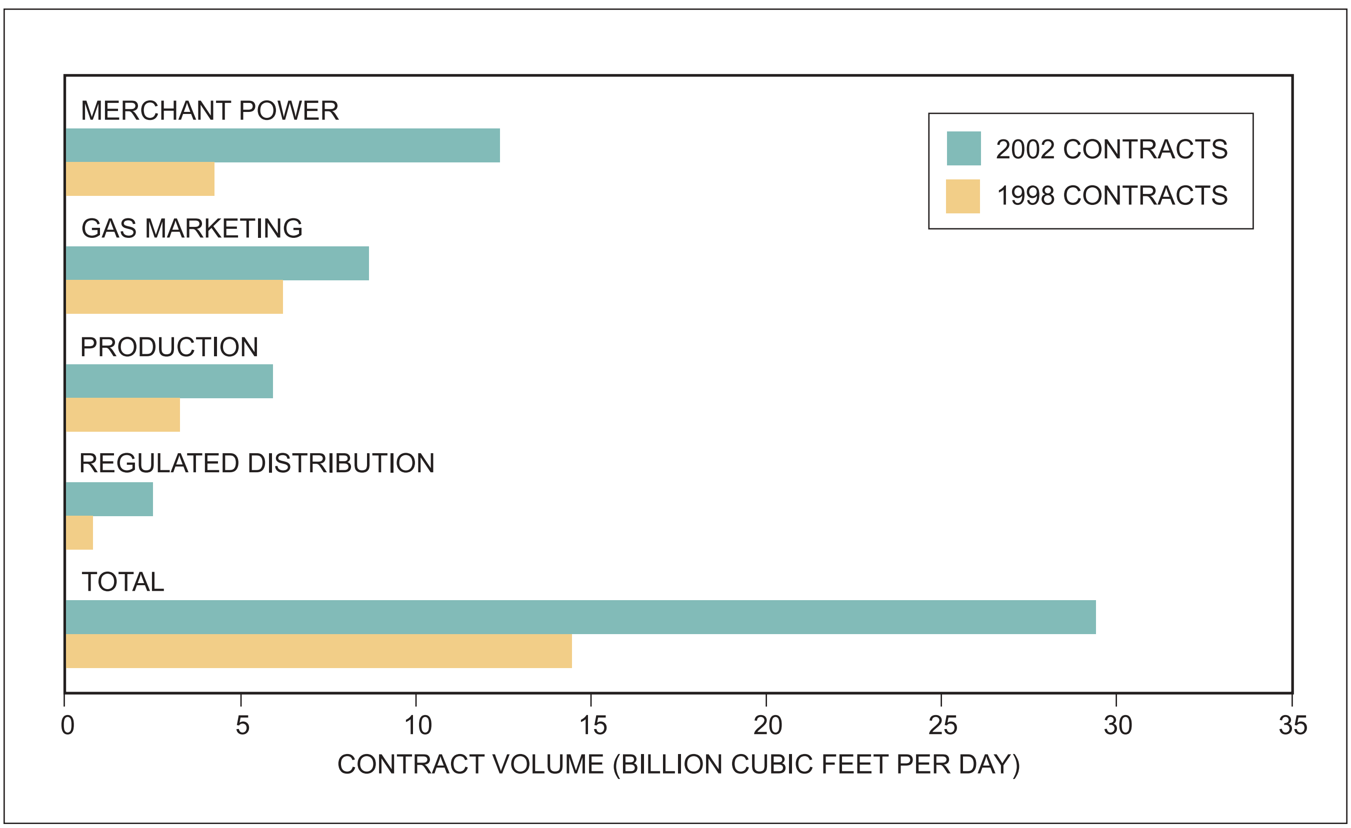

Figure T-12. Marketer Sub-Types, 1998 & 2002 capacity which increased by 2 BCF/D during the period from 1998 to 2002. The firm contracts added during this period had an average duration of 9 years. At year-end 2002, Producers held 12 BCF/D of firm pipeline capacity. The six largest gas producers in North America contracted for 52% of this capacity, with average contract duration of 10 years, as can be seen in Figure T-13.

Most of the increase in firm transportation capacity during the past five years was related to the development of supply basins. The developments included the Maritimes & Northeast Pipeline (Eastern Canada/Nova Scotia offshore), which was primarily supported by producer shippers with 15- to 20-year contracts, and the Alliance Pipeline (Western Canada Sedimentary Basin), which was based on producer shippers/owners with 15-year contracts.

The Producing Sector focuses on shipping their equity gas to market points. Where supply area pipeline constraints exist in conjunction with growing production, producers have often supported new transportation infrastructure projects to alleviate or minimize such constraints. In the Rockies, independent producers have contracted short-distance pipeline expansions to move their gas to more liquid points or points where they can access capacity that exits the region. The Medicine Bow Lateral in Wyoming is an example of such development. In the Gulf of Mexico, numerous pipelines have attached offshore pipeline developments to the existing onshore infrastructure. Recent examples of this latter type of development include the Discovery Pipeline, Destin Pipeline, and East Breaks Pipeline.

The timing and location of LNG import terminals will have a pronounced impact on the supply/demand balance during the study period. Terminals located in producing areas can be viewed as providing supply replacement for declining domestic gas production. Since these terminals, such as Lake Charles and Cameron LNG, are in an area of existing major pipeline transmission infrastructure, they will need only minimal incremental pipeline infrastructure development to obtain access to the current gas transmission grid. For terminals being developed or proposed in consuming market areas, such as the Baja and two northeast U.S. projects, take-away gas pipeline infrastructure will also need to be developed to link these resources to the pipeline grid. It is anticipated that LNG sellers will contract for these required infra-

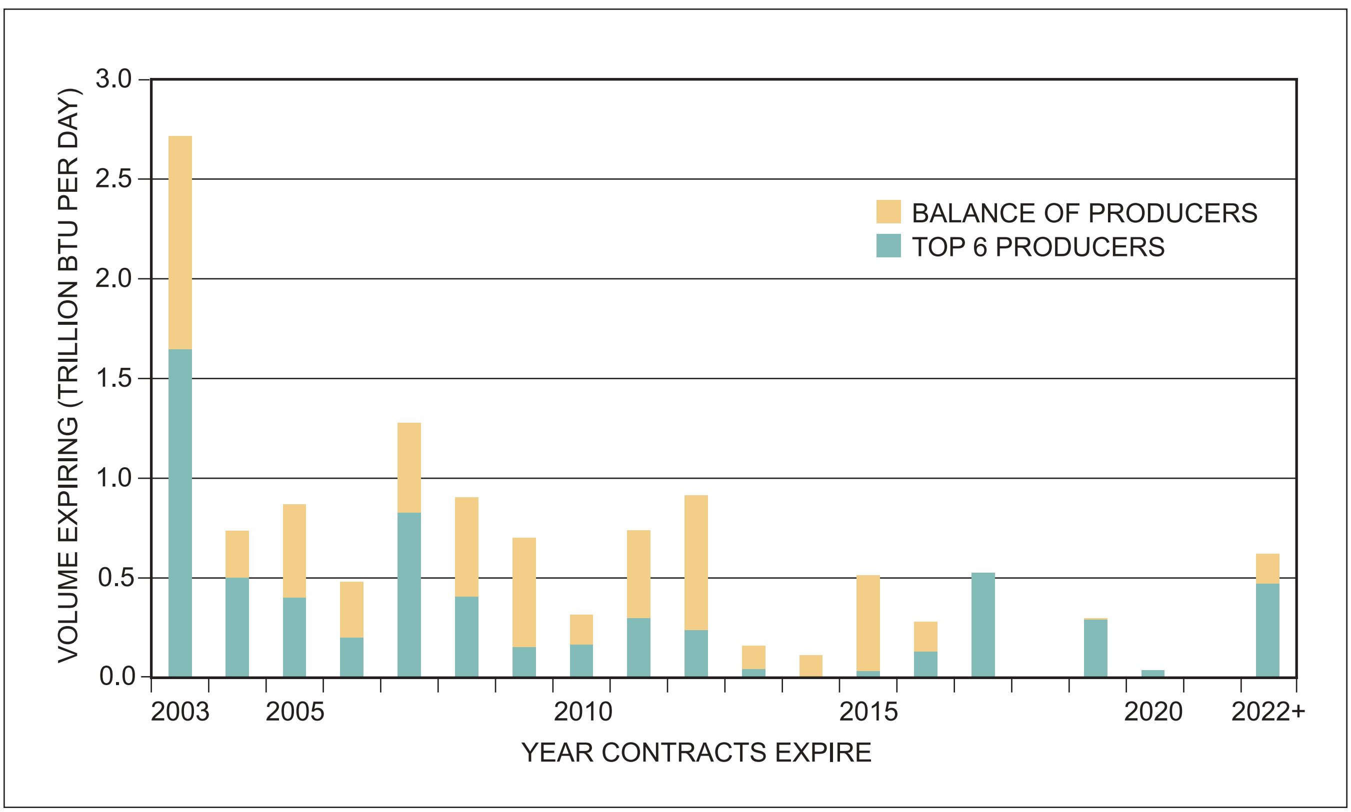

Figure T-13. Firm Contract Expiration by Year, Production Sector structure developments from the LNG terminals to major pipeline interconnects in order to ensure their supplies can reliably reach the consuming markets without hindrance or constraint, a continuation of their historical rationale.

The *LDC Sector* holds the largest amount of firm capacity of all the sectors discussed. Between 1998 and 2002, LDC firm capacity remained constant at 50 BCF/D. A key issue faced by the distribution and transmission industries in the next 5 years is the recontracting of existing LDC contracts for firm pipeline capacity as, during that period, 71% of all contracted LDC firm transportation capacity expires. This "termination window" is largely reflective of a similar picture during the gas unbundling initiative in the early 1990s, when large amounts of firm transportation were available for recontracting, but also results somewhat from more recent LDC choices to enter into shorter-term contracts. As some Public Utility Commissions (PUCs) discourage or will not support their entering into long-term contracts, the future level of longer-term LDC contracting is currently an unknown. Another principal factor that has limited LDC interest in longer-term contracts has been the advance of consumer choice programs, wherein residential and commercial customers can select their natural gas providers. Growth in these consumer choice programs is leveling off in many states, however, and in some cases retail marketers may have exited the business, causing a potential shift of consumers back to the LDC and/or the remaining marketers.

As part of the consumer competition process, states have had to specify which entity should provide service to high-risk customers or to customers whose supplier has failed to perform. Increasingly, state regulatory agencies are designating LDCs as the correct party to provide service to these customer classes, e.g. the provider of last resort (POLR). In some states, as a result of this POLR designation and the success they have had in retaining market share in spite of the advent of gas marketer competition, some LDCs are not expected to be as likely to reduce their overall firm transportation capacity requirements during the next several years. As the issue is fluid, however, LDCs facing these recontracting decisions may choose to only commit to short-term contracts to limit their exposure to continuing changes of rules and roles in their local competitive environment.

In this study, residential and commercial demand growth projections are relatively modest, at approximately 1% per annum. Consequently, LDCs are not expected to be contractors for significant new construction of firm pipeline transportation infrastructure, rather they will likely be candidates for additional storage services and related transportation capacity from storage to citygate.

3. Capacity Contracting Decisions

Market fundamentals, i.e. supply, demand, and resulting prices, will continue to signal the need for the construction of new pipeline capacity. For example, a production company which projects increasing supply volumes in an area of constrained pipeline capacity may have a need to subscribe to new capacity as a means of avoiding pipeline transportation curtailments and negative impacts to flowing gas. The ability of Cheyenne Plains to obtain contracts and move forward with additional infrastructure exiting the Rockies with a 2005 start-up, despite a belief by some that the very-recent 900 MMCF/D Kern River Expansion would provide ample capacity to transport supply away from the region, is a good example of other parties recognizing a continuing need for new pipeline infrastructure development and acting upon such.

Similarly, an LDC with increasing customer demand may have a need to solicit development of new infrastructure capacity. In both supply and market area developments, a decision to contract for new pipeline capacity may need to be considered and effected prior to the existence of an explicit price signal in the market, as many projects require years to plan, permit, and construct. Delaying expansion activities until explicit price signals materialize, or a sense of certainty can be determined, may fail to provide capacity when it is actually needed.

Besides the projection of future supply/demand constraints, a more obvious signal for pipeline transmission system development is a sustained increase in price between different geographic locations. A price differential between any two points is referred to as a locational "basis", or basis differential. Basis differentials may be higher or lower than a pipeline's maximum tariff rate, generally higher when capacity is fully utilized in an area or lower where surplus pipeline delivery capacity generally exists. The former, if sustained, may signal the need for new pipeline capacity and can create interest in pipeline expansions or new infrastructure construction. The large basis differentials between the Wyoming supply region and the

Pacific Northwest, California, and Mid-Continent markets, which have recently exceeded $2.00 per MMBtu, signaled the need for new regional pipeline developments. Market participants have responded to this price signal with a commitment to long-term capacity contracts, thus leading to the expansion of Kern River Pipeline and the construction of the Cheyenne Plains and Bison pipeline systems.

Short-term basis differentials by themselves, however, are not a definitive signal of the need for infrastructure development. If there is excess supply available to a market, then market forces create significant pressure to reduce both the gas commodity cost and the price that shippers are willing to pay for transportation capacity (i.e., surplus). Given the seasonal nature of the gas market and the need to reliably serve winter peak demand, many pipeline systems are designed to have sustainable capacity above their average daily demand for much of the year. This results, then, in short-term daily pricing for transportation capacity that may be below the pipeline's maximum tariff rate for much of the year. Thus a basis differential that exists for a sustained period of time is more reflective of the value of long-term capacity contracts and is a better barometer for infrastructure investment decisions. In fact, long-term basis relationships are the principal metric utilized to determine the need to build pipeline capacity in the modeling efforts underlying this study.

For volumes of gas that producers or buyers determine they "must flow," the value of transportation can exceed the basis differential. The need for future reliable services explains why some pipeline projects can achieve the critical mass of contractual commitments necessary to support development of a greenfield system despite observed basis differentials that are less than the expected cost of transportation. Iroquois Pipeline and Maritimes and Northeast Pipeline in the northeast U.S. are examples of this type of project.

The price differential required for a project development signal to be recognized in the market is intricately tied to a convergence of many unique factors, including pipeline construction cost, the supply availability, and the expected market demand. In general, transportation cost per unit volume, both in terms of capital and operating costs, decreases as the capacity of the pipeline to be constructed increases, i.e., the economies of scale principle is applicable. For this reason there is a strong economic incentive to pursue development of a pipeline with a large capacity. However, the market frequently does not require high volume pipelines, even though they may be more economically efficient. As such, determining the project size that balances available supply and demand at rates competitive with potential shippers' alternatives is key to shipper participation, regulatory approval, and ultimate project success.

With such market forces at work, the negotiation for new capacity evolves into an ongoing discussion between producers, pipelines, and consumers, each of whom are balancing separate projections of the supply available and the growth in market demand. Not only are there cost and volume issues, but the timing of the pipeline start-up may also be a critical consideration. Usually, a number of "open seasons" or other marketing efforts are conducted by pipeline developers before a final decision is reached regarding the proper size and configuration of a pipeline project and binding agreements are signed.

For a major pipeline expansion or a new project, the maximum pipeline tariff or transportation rate is normally, but not necessarily, calculated using an annualized cost component and contract volumes. Thus, the applicable tariff rate is frequently the same in a low-demand month (April) as in a high-demand month (January). This non-varying cost for firm transport, when combined with large swings in seasonal market demand, can result in large variations in capacity utilization, citygate prices, and the realized market value of pipeline capacity.

This seasonal variability in the realized market values of pipeline capacity may increase its worth. The increased worth results from having the downside risk of holding capacity capped at the rate paid for the capacity while the upside value is not limited in today's market. Since the firm shipper has bought the right to call on the capacity at any time, the combination (capped costs, assured access, unlimited sales prices and observed price volatility) creates a potentially valuable option. Because gas prices are volatile, the same relationship holds true for monthly and daily price time intervals. In all three cases, the holder of transportation capacity has asymmetric risk with a fixed downside exposure and an uncapped but highly uncertain upside potential. Some market participants would like to "hold" this option; others would not. This option also has value in the secondary market for transportation and storage capacity that has developed. However, this opportunity is troublesome for some LDCs where regulatory barriers exist that impede them from contracting for capacity to serve their customers.

This basis volatility and associated financial exposure can increase the difficulty in obtaining a critical mass of binding agreements necessary to justify the construction of new pipeline capacity. Since each party may have its own projection of future basis value of capacity, its own view as to the "option" value of holding the capacity, and its own ideas of what other competitive options may be available, achieving the level of contractual commitments needed for project development can be time-consuming and difficult.

During the late 1990s, the difficulty in obtaining commitments from a sufficient number of parties with such diverse views was somewhat offset by the ability of shippers to purchase financial instruments, such as swaps, that provided a financial hedge for the potential basis risk associated with entering into a long-term capacity contract. For an additional fee, parties could execute financial transactions with third party entities that provided a form of insurance for all, or a portion of, its perceived forward, physical capacity position risk. Recently, however, the turmoil in the gas marketing sector has greatly reduced the availability and reliability of parties offering these "hedging instruments," thus a valuable tool which had previously assisted parties in making capacity contract decisions is no longer as readily available.

4. Timing of Responses

The response time or "lag" between the occurrence of a price signal, i.e. an increased price differential between two points, and the time at which a proposed project can gain sufficient commitments to go forward can vary significantly between one project and another. The extent of the lag will depend on the upstream supply expectations, the projections for market demand, the size of the basis differential, and the time period the basis has existed. In cases where a number of companies are in agreement that the basis is significant and lasting, the period between a project proposal and construction can be fairly short. In the case of the most recent Kern River Expansion, the developer held an open season in August 2000, filed for a FERC certificate in November 2000, made a final investment decision in March 2001, and was in commercial operations by May 2003.

One of the challenging problems in new pipeline project development is the fact that non-contracting parties on both ends of the pipeline system may ultimately benefit from new capacity construction because of the new infrastructure's impact on price and basis value. For example, all western Canadian producers benefited from the price increase that followed the development of the Alliance Pipeline, not just the producers who actually contracted for the capacity to Chicago. As is typical in a free market, there may be considerable jockeying among potential project shippers to contract for only the minimum (or no) amount of capacity while still having a pipeline project proceed. Pipelines, of course, must seek fairly large projects so that the benefits of scale can keep proposed costs and tariffs down. Since a perceived ideal position is to allow others to commit but to still be able to reap all or a portion of the benefits from a removal of a capacity constraint, gaining a critical mass of long-term commitments can be problematic for a pipeline developer. This is why some projects have multiple open-seasons, why competitive projects surface when previously announced projects appear to falter, and why some projects just don't proceed. This is typical of competitive markets at work, but can be very frustrating for pipeline developers and parties who desire to see such projects implemented. The Cheyenne Plains and Northeast ConneXion projects are both examples of projects that were marketed (and re-marketed) over the course of several years before a critical mass of shippers was finally assembled. The Cheyenne Plains system held three separate open seasons, beginning in 1999, before achieving sufficient contract commitments to justify the project in 2002.

New capacity projects can take years to develop when important consuming sectors are either inhibited or not motivated to sign long-term firm contracts. Merchant power generators, for example, may choose to not subscribe to firm contracts for all or a portion of their supply, as these important gas consumers may not believe a 24-hour, 365-day pipeline service is required, or the insurance value associated with capacity certainty is not cost-effective. Generators may also prefer, instead, to utilize released firm capacity or interruptible capacity if they perceive little financial exposure for reduced fuel reliability.

Over 128 GW of gas-fired capacity was built between 1998 and 2002; many of these facilities chose to not commit to firm pipeline transmission capacity. As such, a growing realization is that, in future years, as gas-fired generation demand increases, many combined cycle gas turbine plants may not reliably operate at their targeted annual utilization factor if additional firm pipeline capacity is not contracted. In addition, many merchant power companies are recently unable to contract for firm capacity on existing or new pipelines due to creditworthiness issues.

Another customer sector that may be disinclined to subscribe to long-term pipeline contracts is the LDC. Since LDCs have been the anchor tenants for most of the pipeline capacity constructed over the last seven decades, continuing market evolution and resultant regulatory policies may have created barriers to long-term capacity contracts that have impeded infrastructure investment. Historically, with an obligation to serve human needs customers, LDCs have maintained a level of pipeline capacity to do such. In the unbundled environment today, certain service requirements are still mandated. Where applicable, regulatory bodies must ensure that providers of last resort (POLR) or other entities providing service to human needs customers – whether gas or electricity – are allowed to make pipeline capacity commitments necessary for long-term service reliability.

Contractual commitments by various parties are critical to the expansion of the pipeline network. However, as different approaches to pipeline contracting are evolving in a changing gas marketplace, there appears to be a new paradigm evolving in contracting practices. First of all, contracts appear to be of shorter term. Second, it is becoming increasingly difficult for pipelines to contract the middle portion of a transportation path. A producer may elect to contract for pipeline capacity only as far downstream as the first unconstrained point, while some LDCs, on the other hand, may choose, or must choose, to only contract for capacity from the citygate to the nearest upstream liquid market point. These points are usually located within a market area, which may be located hundreds of miles from a supply region.

This trend creates a bifurcation in the pipeline capacity market. This "gap in the middle" is an anomaly of the current natural gas marketplace; this dilemma will affect the decisions of pipeline operators concerning the creation of new capacity and sustaining the existing capacity levels between the supply and market regions. Left to itself, the natural gas industry will find equilibrium. Clearly, however, governmental policies should not inhibit the ability of LDCs and POLRs to extend their contracts into the supply regions.

5. Financing Construction

Interstate pipelines have regulated rates of return that are reviewed and approved by the Federal Energy Regulatory Commission (FERC). The allowed rates of return on the capital employed in a project are established in large part by determining the pipeline developer's cost of capital, i.e., its costs of debt and an industry proxy group's observed cost of equity. Historically, most of the capital raised for new pipeline construction has been in the form of debt, as debt costs less than equity. Although a high debt load can increase the risk of default, in the past this risk has been offset by the revenues coming from long-term firm capacity contracts. In the current economic environment in the United States, however, debt (both existing and new) is no longer considered as attractive. Instead, the investment community has emphasized a new focus on reducing corporate debt. The natural gas pipeline industry is not immune to this type of financial pressure, thus new projects will have to be carefully analyzed and structured before additional debt is taken onto the corporate balance sheet.

The willingness of creditworthy shippers to subscribe to long-term capacity contracts has allowed a number of pipelines to be constructed utilizing project-based financing, instead of general corporate debt. Project financing allows for non-recourse debt, which does not impair the balance sheet of the parent company. This financing approach allows capital to be raised more quickly, and usually at lower cost, than issuing general corporate debt. However, the trend to shorter-term contracts by capacity holders (as discussed above) has somewhat reduced the ability of pipelines to use this method of obtaining expansion capital, as lenders want to match the lengths of contracts (with creditworthy shippers) with the proposed project's loan repayment period, which in the case of new pipelines is typically fifteen to twenty years. With a trend towards shorter-term contracts, there is a fundamental mismatch between the expectations of capacity subscribers and pipeline lenders that must be resolved if project financing is to be a primary vehicle for obtaining capital in the future.

Parties that have not traditionally owned interstate pipelines, including producers and LDC consortia, have recently shown an interest in developing such systems. The focus of producers has generally been the construction of systems to transport gas from constrained supply regions. The Alliance, Maritimes and Northeast, and Destin pipelines are good examples of this type of producer-led development. Similarly, consortia of LDCs have successfully developed short-haul pipelines within the market regions, again focusing on the de-bottlenecking of existing area constraints. Examples of LDC consortia projects include the Iroquois, Vector, and Guardian pipelines. The active involvement of producers and LDCs in the construction of new pipelines has been very beneficial to the industry, especially during the last ten-year period.

Capital-in-aid-of-construction (CIAC) has been used for years to finance laterals linking new supply and/or markets to the existing interstate network. A shipper provides the capital for construction in return for transportation services. Both parties benefit as the pipeline company is able to conserve capital while the shipper obtains the desired service. Similar to this method is a customer "self-build." In a self-build, the customer builds its own lateral to the connection with the interstate pipeline. In this case, the customer may continue to own the lateral or, with appropriate regulatory approval, they may cede ownership to the pipeline. Although both approaches facilitate the construction of laterals for segments as much as fifty miles in length, they are inadequate for the construction of larger pipeline extensions. This is because longer distances and the inclusion of multiple shippers may subject the builder to regulation by federal and/or state authorities.

D. Construction Challenges

1. Project Approval

Initial pipeline route selection and surveys are conducted by the pipeline company that is developing the project. Environmental, safety, population density, operational, and construction cost concerns are all considered in helping to determine the preliminary routing of the pipeline for further field surveys and submittal of the route to the reviewing authorities, public comment, and approval.

The project routing selection involves the review of aerial photographs, soils maps, population density surveys, and future land usage maps. The process includes the input from many diverse groups, which affect the timing of final route selection, length of the route, and ultimate cost.

Regulatory approval of pipeline proposals involves agency reviews at the federal, state and local levels. Review levels and procedures by agencies vary significantly from state-to-state with the only common review level and approach occurring at the federal agency level. Where multiple-level agency reviews exist, approval of pipeline projects can sometimes be delayed by certain lower-tiered agencies. Examples of review and approval durations range from 6 months to 42 months, depending upon the number of agency approvals and complexity of the project. FERC has been making great strides in improving the time for approval, but many times, the project is held up by some other agency even after FERC has issued a certificate. These delays in project approvals can be a significant driver of project cost increases. Also, as projects are increasingly delayed, prospective customers may begin to look for alternatives and ultimately terminate their agreements, with such withdrawals sometimes causing entire projects to collapse.

Previous discussions between the industry and the federal government on the difficulties in coordinating a pipeline project among the various federal agencies led to a Memorandum of Understanding (MOU) in 2002. This MOU established a framework for early cooperation and participation among "participating agencies" to enhance the coordination of the regulatory processes through which their environmental and historic preservation activities could occur. Review responsibilities under the National Environmental Policy Act of 1969 are met in connection with the FERC authorizations that are required to construct and operate interstate natural gas pipelines. Among the participating agencies are the U.S. Army Corps of Engineers, U.S. Forest Service, National Fisheries, Land and Minerals Management, U.S. Department of the Interior, U.S. Department of Transportation, Advisory Council on Historic Preservation, FERC, Council on Environmental Quality, and the U.S. Environmental Protection Agency.

The National Environmental Policy Act requires federal agencies to evaluate the environmental impact of major federal actions significantly affecting the quality of the human environment. The MOU encourages early involvement with the public and relevant government agencies in project development to foster a process to facilitate the timely development of needed natural gas pipeline projects. The agencies are to work together and, with applicants and other stakeholders as appropriate, identify and resolve issues as quickly as possible, attempt to build an early consensus among governmental agencies and stakeholders, and expedite the environmental permitting and review for natural gas pipeline projects.

The chair of the White House Council on Environmental Quality has stated that the new procedure will improve coordination and speed up natural gas pipelines that currently encounter years of environmental reviews by various federal agencies. The extension and full integration of this type of coordination to the state level will also be required, however, before genuine progress can be made.

Further progress could be made by developing a Joint Agency Review Process that would coordinate activities between federal, state and local agencies. A lead agency (perhaps FERC) could be assigned the authority to complete the review/approval in a timely manner, while meeting the concerns of all agencies and stakeholders. In order to be effective, this process should be the "governing" process, i.e., not to be further limited or delayed when approvals have been received to proceed from other responsible agencies. The areas of greatest concern in this regard are requirements of the U.S. Army Corps of Engineers, Coastal Zone Management Act, and Section 401 of the Clean Water Act, all of which could hinder the orderly implementation of FERC certificates. One example of this concern is the escalating use of the Coastal Zone Management Act to delay pipeline progress as exemplified by the serious delays currently experienced by the Millennium and Islander East Pipelines.

The recent FERC emphasis in the United States is to identify key stakeholders early and involve them in the process at the outset of a proposed project. An effective approval process allows third parties to become involved during designated comment periods. In these designated comment periods, external stakeholders, such as landowners or other special interest groups, are given the opportunity to voice any concerns with the pipeline route. Delays in project approval and increased costs can occur when external stakeholders come forward with significant changes in the proposed pipeline route, but this is a necessary part of the review process. FERC is required to accept and reasonably address all stakeholder comments, and thus can ask the pipeline company to research and possibly resurvey each proposed route change, involving both civil and environmental surveys, which can result in significant project delays and unanticipated cost overruns. The Joint Panel Review Process would minimize these inefficiencies, as the process should, via significant upfront participation, agree upon a route or options thereto which can uniquely be investigated.

2. Construction Issues

In addition to interventions in the approval process, delays can arise from stipulations in the approval with regard to construction issues, such as short time windows for laying pipe, work space limitations in certain areas, or mandated construction methods. The limited time periods or "construction windows" are frequently required by various state and federal agencies and can add significant costs and delays during construction of a pipeline project. Construction windows are typically imposed by environmental agencies to restrict construction activities through habitat areas or at water crossings to specific days or months of the year. These restrictions require careful planning of construction timing and implementation, and even then weather conditions or other unanticipated delays (labor, materials, etc.) during the construction window can make it difficult to complete the work during the allotted time period. If a project is delayed past the end of the construction window, then the operator may have to wait until the opening of the next window (and this could be up to a year later) to complete the project, often at substantial additional cost to the project.

Environmental agencies can also require pipeline companies to limit the width of pipeline construction rights-of-way to reduce tree clearing or other earth disturbances. Such restrictions can require hauling off of ditch spoil during pipeline installation. In some of these cases the pipeline must then be installed by stove-piping the pipeline at the location (welding one or two pipe joints at a time and then burying them as you go – a very tedious process) or by welding a portion of the pipe at a more accessible offsite location and hauling it along the right-of-way with large equipment called "side booms." These construction requirements due to work space limits will increase project costs substantially. These are, of course, further complicated and magnified, if construction windows are involved.

Mandated construction techniques often occur when pipelines have to cross water bodies, wetland areas, or major roadways. Environmental agencies, either state or federal, can order the use of special techniques, which can include horizontal directional drilling (HDD), special top-soil separation, and use of wood mats in wetland soils. Horizontal directional drilling of water crossings can prevent disturbance of plant and fishery species, but represent a risk of not completing the crossing (by failure of the drilled hole or stuck pipe during pull-back operations) and adds cost to the project. HDDs can add in the range of $200 to $1,000 per foot in additional costs to the length of pipe. In some instances additional HDDs are being required as an environmental mitigation tool, such as requiring them at small creeks and rivers where conventional crossing methods might have been used historically. Use of mats at wetland locations can add an additional $50 to $100 per foot to the pipeline costs in areas where they are used.

Environmental agencies can also require offsite "mitigation" in wetlands construction. Frequently the mitigation involves obtaining environmental credits or may involve mitigation by compensation. The purchase of property for offsite mitigation can add substantial delays and costs to the project. In many cases, the agency will not sign-off on construction approvals until the property identified for mitigation has been purchased. Delays occur since the pipeline company has to search for suitable acreage for mitigation, obtain necessary clearances for the mitigation site, and then complete the purchase of the land. With the high level of mitigation ratios (two to one is common and five to one occurs), as well as having to establish the mitigation site for long-term, pristine land use quality requirements, mitigation lands can be very expensive to purchase.

3. Post-Construction Monitoring and Operating

Development responsibilities can extend beyond the actual construction period with the increasing requirements for ongoing monitoring and repairing the pipeline corridor. Environmental agencies are now requiring pipeline companies to develop and implement a long-term monitoring program to monitor, document and correct/repair pipeline corridor restoration. Examples of current FERC and/or state standards include: a) Uplands – monitored for the first growing season and the second, if necessary, and b) Wetlands – no full width clearing; a ten-foot wide corridor over the pipeline to be maintained in an herbaceous state; and clearing only within a limited distance of the pipeline.

Inadequate or damaged pipeline corridor restoration/mitigation must be repaired or replaced to original pre-permit conditions. This ongoing monitoring and repair program can add significant costs to the project depending upon environmental sensitivity of the lands, streams and rivers crossed.

An implementation barrier involves issues related to usage of equipment such as compressors and meter regulator stations. This type of equipment must be monitored for environmental emissions such as NOx and noise. The monitoring of these levels necessitates the installation of additional monitoring equipment, sound-proofing, etc., and/or might limit the use of the equipment such as the number of run-time hours per month (or year) or prohibitions against running of the equipment at night.

4. Private Parties

Besides managing its interactions with state and federal agencies, the pipeline industry must also coordinate its relations with private parties. The FERC has conducted several seminars and prepared a document outlining their desire for more early involvement by all stakeholders in the FERC approval process. FERC encourages pipeline companies to seek out greater involvement from the various groups early in the planning process so those who are interested can participate in the decision-making process. Agencies (local, state and federal) and citizens are encouraged to get involved early and make their views known to the project sponsors. FERC's view is that earlier and more-productive involvement will lead to better project designs and less-contentious FERC and other agency processes.

At times, however, a pipeline's best efforts to negotiate rights-of-way agreements with outside parties are simply unsuccessful. In areas where there is no viable alternate route, the Congress has allowed for the use of eminent domain proceedings. Eminent domain is the legal process whereby a pipeline or utility company can obtain property rights or an easement to a route and install the pipeline on an objecting landowner's property. This process is avoided as much as possible by all pipeline and utility companies, as the cooperation by company and landowner is in everyone's best interest for both the short and long term. If the pipeline company and landowner can not agree upon a route or settlement cost for a property easement, then a federal or state court can determine and provide a lawful settlement payment amount to the landowner and thus secure the easement for the pipeline company.

A special case of where even the eminent domain principle is at issue involves the lands of First Nations people. Routing of pipelines through regions of aboriginal lands must include an extensive plan which incorporates the deep concerns that the indigenous people have for the land which the proposed pipeline will transverse. Community inclusion of the First Nation peoples in pipeline routing, environmental studies and monitoring of construction activity is standard practice. However, the complexity and detail of this overall process can upwardly impact project costs and may be a source of timing delay in getting final project and/or construction approvals.

5. Typical and Extreme Timelines

The typical project timeline for a major interstate pipeline project with an Environmental Assessment (EA) that is filed under an FERC 7 (c) certificate is normally 12 to 20 months from project initiation to the reception of the FERC authorization to construct. The typical project timeline for a FERC 7 (c) filing for a major project requiring an Environmental Impact Statement (EIS) from project initiation to FERC authorization to construct, is normally 18 to 24 months.

Once permits are obtained and land is acquired, most U.S. pipeline construction projects are typically constructed in one calendar year or construction season. In some cases, directional drills for river crossings may be completed prior to the start of cross-country pipeline work and may be a regulatory requirement to be completed before the full authorization to construct is issued by the FERC. Projects that transverse through areas with issues such as endangered species, high-population-density areas, historic artifacts, noise mitigation, and safety concerns require 6 to 18 months beyond a more typical project timeline.

6. Cost Trends

One clear trend in pipeline construction in both the United States and Canada is for the continuing escalation of costs. Costs have been increasing about 3 to 4% per year, above the projected 1.5% annual rate used in the study. Materials costs do not play a part in this escalation as they are generally aligned with the raw materials costs, which have not increased significantly in recent years. Pipeline developers are attempting to offset this trend to higher costs by using stronger steels, which allow for higher operating pressure and greater volumetric flow, as well as more efficient pipeline laying techniques. Contractors generally have become more efficient at installing pipelines by using high productivity processes such as automatic welding, but these savings have been more than offset with increased labor costs. Though the rising costs associated with new construction are somewhat of a barrier to infrastructure development, the modest nature of the overall cost increase is not expected to necessarily make required infrastructure projects uneconomic.

E. Operational Challenges for Infrastructure

If all the flows entering and exiting a pipeline were constant in nature, then it would be a relatively easy system to operate. Operators could set the compressors along the system to calculated levels and the pipeline would be "balanced" thereafter. This is called a "static" system in engineering and unfortunately it is not reflective of events in the natural gas industry.

Instead, natural gas transmission pipelines are dynamic systems with conditions constantly varying at large numbers of receipt and delivery points. Existing natural gas wells experience mechanical problems, freeze offs, and production declines that change deliveries into the system. At the same time, new gas wells are added and consumers vary their demand according to temperatures, industrial processes, and electric generation needs. The throughput capacity of a system thus varies with the amounts of gas entering and exiting the system, the pressures at each inlet and exit point, and the locations of these supply and demand points, particularly with regard to compressor stations. For traditional long-haul transmission systems, these compressor stations are installed at roughly 40 to 80 mile intervals and are used to overcome the pressure loss within the pipeline due to friction of the moving gas against the wall of the pipe.

1. Gas Delivery Variations

Within the dynamic system described above, there are three major consumption cycles that affect the transmission industry. The first is a seasonal variation of demand, from winter to summer. The second cycle is a demand variation within a season or a month. The last is the change in hourly consumption during a daily cycle.

The seasonal variation exists largely due to consumption within the residential and commercial (R&C) demand segments. A large component of annual natural gas demand in the United States, approximately 36%, is for residential and commercial consumers. These consumers rely on natural gas for space heating, water heating, cooking, and other purposes. The first component, space heating, comprises approximately 70% of the R&C load, or 25% of total U.S. annual consumption of natural gas. Consumption for space heating, however, is closely tied to the winter heating season. Thus approximately 50% of natural gas consumption occurs during the five winter heating months, November through March. Figure T-14 shows the strong seasonal nature of natural gas consumption in the United States; Figure T-15 indicates the impact of residential consumption on the national total.

a. Seasonal Flow Design

Given the strong variation in seasonal demand, the industry has found it economic to use storage fields to manage the large differences between winter and summer consumption. Storage is discussed in more detail later in this chapter, but traditionally, and in large part still today, gas is injected into the storage reservoirs in summer and withdrawn in winter. This allows pipelines and wellhead production to operate at a more consistent and more efficient annual level.

As part of the industry's drive for economic efficiency, transmission lines connected to market area storage fields (in California, the Midwest, and western Mid-Atlantic) have often been constructed for different capacity levels from the supply areas to the storage fields than from the storage fields to the markets. The segment from supply to storage is typically designed based on average-day levels while that from storage to the market is based on a peak-day requirement. This design recognizes that storage withdrawals must be incremental to flowing supply and could potentially inhibit long-haul transport from the supply regions unless capacity downstream (on the market side) of storage was increased. It also allows the market to efficiently value the options between making an investment in storage and short-haul transportation versus the development of long-haul capacity directly from a supply region.

This dual capacity system on the upstream (production) and downstream (market) sides of storage has

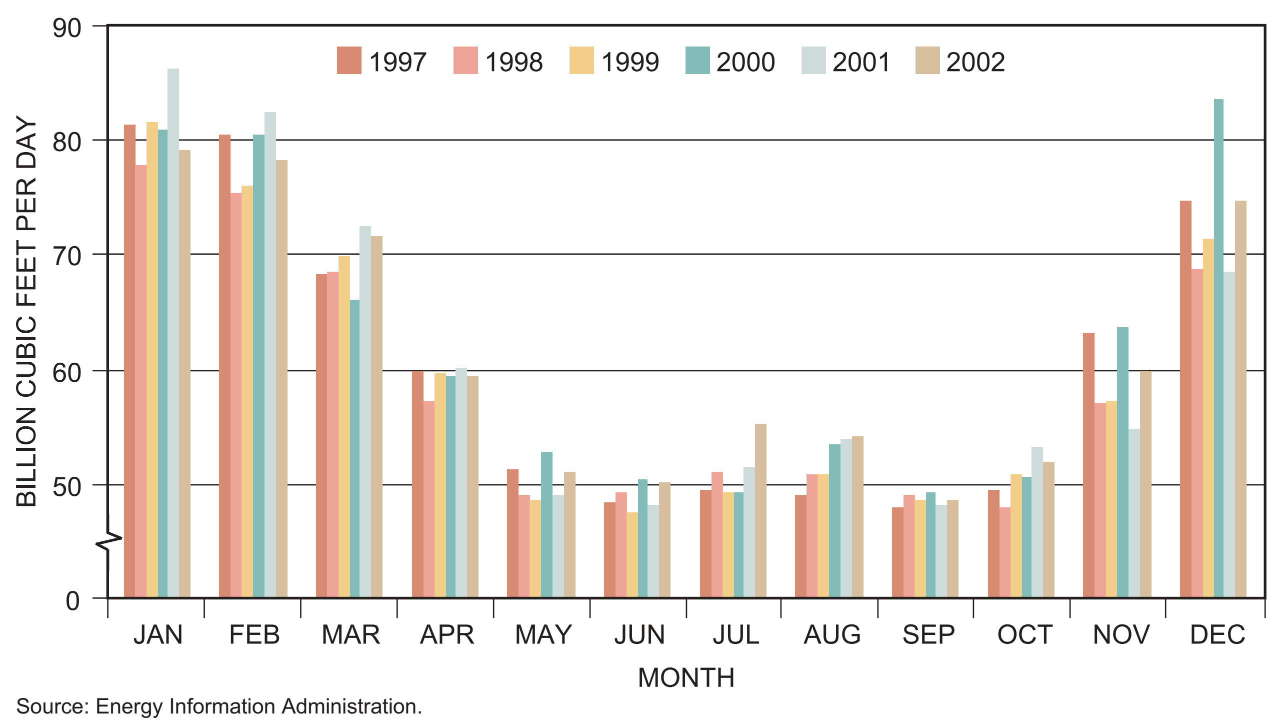

Figure T-14. Monthly Consumption Data

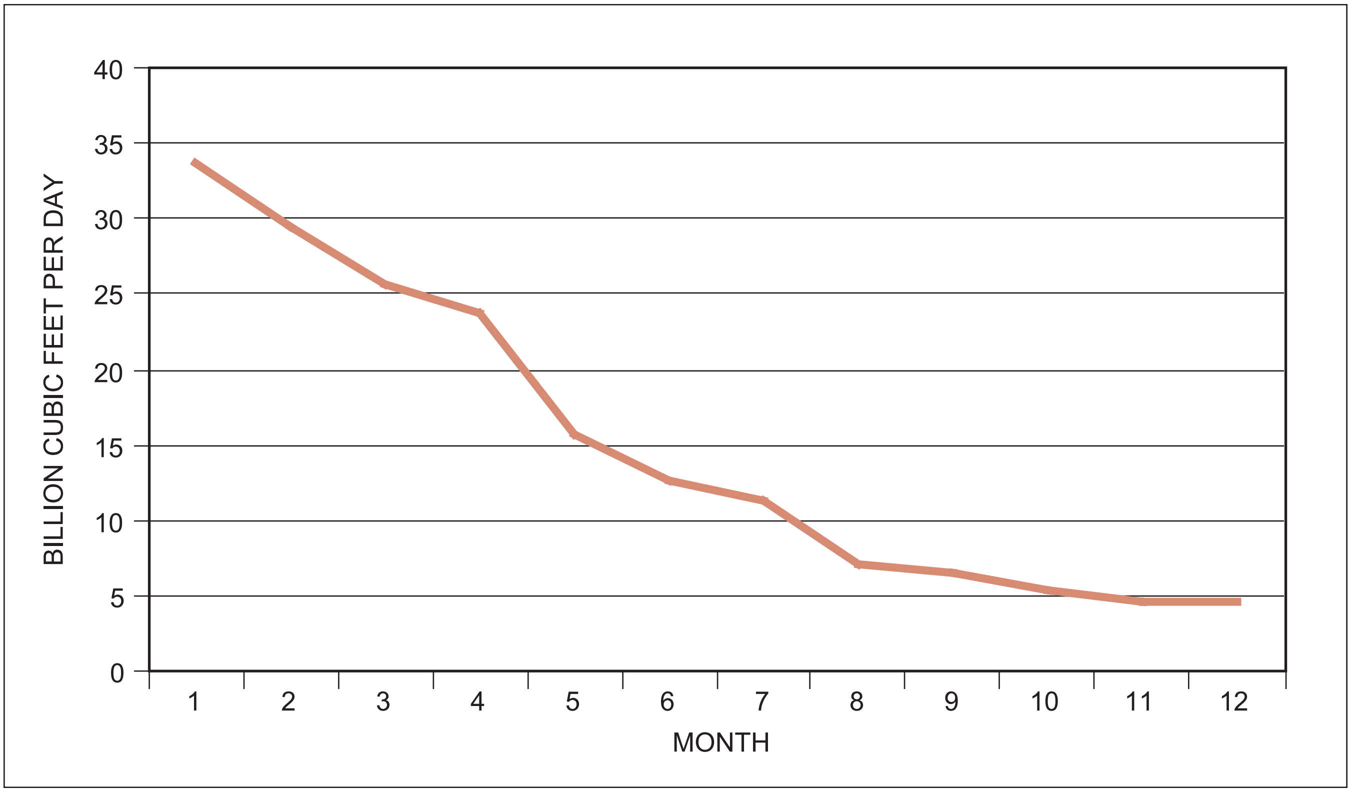

Figure T-15. U.S. Residential Demand in 2001 by Month, Sorted Highest to Lowest

worked well for many decades. The growing utilization of natural gas-fired turbines in the electric generation market is raising concerns about the effect on the summer pipeline and storage capacity usage, however. What used to be a weaker demand period for gas supply and the pipeline transmission network in the summer months is now growing rapidly stronger as gas-fired generation is used to meet air conditioning cooling demand. As summer cooling demands continue to rise over the next 25 years, the increased call on pipeline transmission capacity during the summer by electric generation will reduce the industry's ability to inject proper seasonal volumes into storage. The resulting competition for capacity on pipeline segments designed for average-day use should therefore raise overall pipeline utilization factors (actual flow/designed capacity) and associated transportation revenues. However, there may be additional expense, e.g. compressor fuel, as the pipeline and storage infrastructure must be more dynamic and more time-of-day responsive.

Pipelines are not designed for "needle" peaks in winter. Storage has not only been used to meet seasonal needs, it has also been used to meet short-term market demand. Storage allows pipelines to "draft and pack" ahead of projected demand increases, e.g. pulling in additional supplies from storage and increasing system linepack ahead of a weather front. With the serving pipeline packing-up first, LDCs and other consumers can be assured of the necessary pressures to support subsequent packing of their systems.

In the case of peak-day local markets, i.e. behind the citygate, storage may be typically required from liquefied natural gas and propane-air facilities. These types of storage are much more expensive than those used for seasonal storage but still are less costly than long-haul transmission infrastructure supporting a peak-day delivery. The demand curve moves sharply higher and almost becomes asymptotic during brief periods of high market demand. Constructing expensive transmission infrastructure that would be used for such a short time duration is not cost effective and storage alternatives, LNG and propane-air, are used instead.

Even the use of localized peaking storage does not completely shield transmission systems from the effects of a peak market demand. In these periods, pipeline customers fill their demands simultaneously with consumption need, often nominating and supplying the gas after the fact. Pipelines may thus experience high short-term drawdowns in system linepack as a result of these peak demand events and storage can subsequently help restore the linepack to acceptable levels. Alternatively, perhaps as a result of a sudden warming trend, pipelines can also experience periods where customers undertake their flowing supply. In this case, linepack increases, thus increasing system pressure, potentially to dangerous levels. In this case, pipelines must inject gas into storage, encourage customers to take their contractual quantities, or reduce supply inputs to the system.

Linepack thus operates analogously to a spring, extending out when demand is high and compressing in when demand is low. When the normal level of linepack has been substantially lowered, it may be refilled through storage withdrawals. But since storage is also heavily used during periods of peak demand, a replacement of these linepack volumes usually occurs soon after the peaking event, not during the actual period of high demand. Thus to maintain a safe pressure balance, pipelines draw upon available storage as needed to restore linepack. Due to limited ownership of equity storage (a result of the FERC-ordered unbundling in the early deregulation period of the natural gas industry) pipelines frequently have to temporarily use third-party storage resources for this limited purpose. The no-notice delivery capability and system balancing function between hourly peaks and daily demands are important system management services performed by pipelines.

b. Intra-Day Markets

One of the issues of increasing importance in the dynamics of the pipeline transmission system evolves from the intra-day market. The market demand during the course of the day can vary considerably due to residential, industrial, and electric generation consumption. Many homeowners, for instance, turn down their thermostats at night only to raise them during the day. LDCs like to “pack up” their systems prior to a cold period, anticipating higher consumption from their customers. A significant number of industrial firms have a larger demand during the daytime hours than the night hours as well. In addition, power plants may want to burn large quantities of gas for the sixteen peak hours of their operating day, while burning much smaller quantities in the overnight period.

Demand from gas turbine electric generators is a significant and growing portion of the swing in the pipeline intra-day demand. Gas turbine and CCGT plants are significantly more efficient than the natural gas or oil fired steam generators they were designed to replace, with CCGT units having a heat rate of about 7,000 MMBtu per kilowatt/hour (kWh) vs 11,000 MMBtu per kWh for steam facilities. The lower heat rate therefore provides a more efficient electricity output. Based on this superior efficiency, CCGT plants will generally be chosen to produce (or dispatch) electricity before their steam-fired plant counterparts and will also stay online longer. When comparing these CCGT units to other plants using alternate fuels, however, the comparison becomes more complex. CCGTs are, overall, more efficient than coal-fired plants but the latter are generally used as electric baseload units (first called in an electric dispatch sequence) generators due to a lower per unit cost of coal relative to natural gas. However, due to their poor performance at cycling on-and-off to follow the electric day demand profile, they must generally continue to operate even in the evening hours at a reduced rate, even though less-efficient, in order to realize the overall benefits of their lower fuel cost. Similarly, nuclear plants are generally electric baseload units because their marginal operating cost is very low, also giving them an advantage over CCGT units for baseload generation applications.

Hydro-generation has a “free” source of fuel (water) but the usage of these units varies somewhat by region. In the western United States, especially the Pacific Northwest, the water containment reservoirs are very large and the plants habitually operate as electric baseload generators. In this region, however, a low winter snowfall may reduce overall water supplies available in the subsequent summer season. This lower water availability may cause the hydro-generating electric capacity to be lowered in order to ensure that reservoirs are not decreased ahead of disciplined water management schedules. If this type of hydro-generation restriction is encountered, the electricity shortfall is typically covered by increased generation at regional gas-fired plants.

In the East, the water containment areas tend to be smaller and their usage shifts to intermediate and peaking electric operation. This region, too, may be impacted by lower than normal snowfall and rainfall.

Another regional variation occurs in the Gulf Coast where gas-fired facilities are extensively used for electric baseload generation. This region provides over

50% of the lower-48 production of natural gas supply and the short distance for pipeline transmission results in a low transportation cost. For this reason, gas-fired generation has been a preferred method in this area for many years.

Though regions differ, this use of gas fired facilities for electricity peaking can cause dramatic changes in natural gas consumption. A single 500 megawatt CCGT plant can burn 90,000 MMBtu per day or 3,800 MMBtu per hour. If a market area pipeline has a total daily delivery capacity of 1 to 2 BCF/D (Tennessee Gas Pipeline in New England or Florida Gas Transmission in South Florida, for example), then a single generation plant turned on to meet afternoon demand can raise consumption on a market area pipeline by 4-9%. The afternoon electric generation demands are thus not easily balanced due to the operating characteristics of a pipeline. The electric market has a profile driven by its electricity consumers and requires an instantaneous response while a pipeline operates best on a steady, ratable 24-hour flow. Pipeline operators, then, must deal with this growing mismatch between electric load characteristics and gas pipeline facility design using the infrastructure they have. A more flexible infrastructure would allow a more effective and more efficient response to these needs; unfortunately, capital expense would be required to accommodate such, as well as necessary filings for tariff service modifications.

It is noteworthy that the electric and natural gas transportation markets have differing cost structures. The electric generation market is priced on baseload, intermediate, peaking, thirty-minute and five-minute intervals. Most pipeline tariffs, on the other hand, are based on an expected, even 24-hour offtake. Several pipelines have offered tariff services based on a 16-hour take, such as Northern Natural Gas (NNG), Natural Gas Pipeline (NGPL) and Southern Natural Gas (SNG), and two are even experimenting with hourly charges. Thus, there is a price opportunity variance between what an electric generator is earning and what a pipeline operator receives for the hourly swing service it is providing; this is often referred to as the "spark spread". Such a price opportunity difference may serve to exacerbate the swing as generators attempt to capture as much of the "opportunity" as possible. Unfortunately, these types of actions may degrade service to other customers, so pipelines may have to notify generators to reduce their offtake.

Another type of system balancing problem occurs due to demand variation, i.e. swing. Customers are involved in a dynamic market and generally cannot specify their needs with precision. In today's pipeline transmission industry, customers nominate, confirm, and schedule their anticipated supply and pipeline transmission requirements a day before their actual usage. The day-ahead scheduling allows supply operators to direct their supply into pipelines at the proper quantities and for pipeline operators to predict the pipeline capacity and compression required to move a myriad of supply volumes to their desired delivery points.

The inability to predict demand with precision is especially true for residential and electric generation customers. Since electric generators must meet swing requirements of residential electric customers also, the two largest sources of pipeline swing demand are closely interrelated. Most large consumers use historical data or predictive models to aid in their daily nomination requests. Reality, however, always differs from prediction and consumers are forced to use intra-day nominations and post-consumption balancing to meet their actual demand. Since each consumer's reaction to its actual market demand affects the pipeline's overall effective capacity, there is a continual effort to balance the pipeline system.

The difficulty involved in making accurate predictions of intra-day demand has caused the industry to balance accounts after the actual consumption. Customers may be forced to "take" gas and balance after the fact, i.e., a no-notice service requirement. In normal operating situations this works well since consumers taking more than their nominated demand may be largely offset by consumers taking less than their nominated volumes. For peak-day consumption, however, many (and perhaps most) consumers may be trying to take more than their nominated volumes. In this case, pipeline storage and/or peaking storage is crucial to keep pipeline systems operating.

It is worth noting that a sudden loss in demand may also cause problems for pipeline operators. If intra-day demand becomes much less than that nominated for supply, the pipeline has too much gas entering the system, which may lead to an increase in operating pressure and begin to approach unsafe operational limits. In this case, pipeline operators must inject gas into storage, request all customers attempt to take their nominated deliveries, and possibly restrict inlet supply flows.

2. Gas Supply Variations

Beyond the difficulty in balancing demand, pipelines must also deal with rapid variations in supply. Field production is itself highly variable, due to mechanical problems, processing plant interruptions, freeze offs, hurricane shutdowns, etc., and this causes pressure swings which affect pipeline capacity and throughput. Individual wells experience declines in production that can range from 2% to over 50% per year. This production decline can quickly change the pattern of inflows to a pipeline system, with new wells in a one location perhaps offsetting or replacing declines in another. The change in the pattern of supply receipt, both the locations and pressure, may significantly affect resultant pipeline capacity.

The effect of the variation in supply location on pipeline throughput capacity can be best demonstrated by the means of a simple example. Imagine a pipeline composed of the following: Supply flows in at the southern end of the pipeline at Point A, followed by a market at Point B, followed by another supply inlet at Point C, and completing with a market at Point D at the northern end of the system. If production at Point C is steadily reduced due to natural declines of the wells while Production at Point A steadily increased due to the addition of new wells, then the ability of the pipeline to deliver gas to Markets B and D may be reduced.

Transmission systems must deal with rapid changes in production, sometimes on a daily level. These changes can be caused by hurricane shut-ins when coastal and offshore production areas are threatened by violent storms, or by freeze-offs when very-cold temperatures cause water in natural gas streams to form ice, which can restrict or completely block production valves.

Because of these dynamics, which are often beyond the control of suppliers and offtakers, pipelines now offer tariffed swing services to provide customers with daily balancing mechanisms. As part of these offerings, many pipelines take on the responsibility of utilizing storage, linepack, and other mechanisms to balance any short-term mismatch in supply and demand. The pipeline is well-positioned to perform these services in a cost-efficient manner due to its ability to review and react to aggregate supply inflows and demand outflows across its entire system. The pipeline thus "sees the entire picture" of the system flow movements and is generally able to react to disruptions ahead of a serious problem.

3. Pressure and Gas Quality Issues

One of the services provided by interstate pipeline systems is the provision of pressure. In order to efficiently move gas, most pipelines in the interstate transmission grid were designed to operate at a maximum of 800 to 1,200 psi (pounds per square inch), as compared to normal atmospheric pressure of 14.7 psi. Newer pipelines have been designed to operate at pressures of 1,200 to 1,800 psi using thicker-walled pipe to withstand these higher pressures.

Customers frequently benefit from these high pressures. LDCs, for instance, use 100 to 400 psi for their distribution system mainlines. They can thus avoid the expense of compression for the portions of their system connected directly to interstate transmission facilities.

Electric generators also receive significant benefits from the provision of high-pressure gas. The new gas turbines, which comprise over 90% of electric generation plants constructed over the last four years, require pressure at 450 to 650 psi to operate efficiently. If these plants are not connected to high-pressure interstate, intrastate or LDC transmission facilities, they may have to install local compression to raise the pressure of their natural gas receipts to the required level at a substantial incremental operating and capital cost.

Besides pressure, another common factor affecting pipeline transmission customers is gas quality, sometimes called gas interchangeability. Natural gas from different supply sources can be composed of different percentages of gases that are produced in conjunction with methane. Gases without heating value, such as carbon dioxide and nitrogen, are subject to strict limits in receipt areas and gas volumes exceeding these levels can be restricted from pipeline access. Non-methane gases with heating value, such as ethane and propane, are often allowed into the transmission gas stream under looser constraints, as they are often removed from the gas stream at area processing plants. This gas quality "conditioning" involves the use of processing plants to remove high Btu content gases, such as propane and butane. The removed natural gas liquids (NGLs) are then frequently used as feedstock for the petrochemical industry. Since propane and butane are considered to have higher values as petrochemical feedstocks than heating gases, they are typically processed out of the gas streams in the supply regions.

In general, pipelines limit these non-methane gases by the heating value of the combined gases. The heating value is measured in terms of millions of British Thermal Units (Btus) where a Btu is defined as the energy required to raise the temperature of one pound of water by one degree Fahrenheit.

Due to different operating conditions, pipelines may vary their upper heating limit to different levels. In general, however, the upper limit in supply areas (1,150 Btu per cubic foot of gas) is higher than that of market regions (1,100 Btu per cubic foot of gas). Typical market area levels of Btu content range from 1,020 to 1,080 Btu per cubic foot.

One concern relative to gas quality is that different levels of Btu content per volume can lead to poor combustion characteristics. The variance in gas quality, with Btu levels either higher or lower than the level for which the burner is set, can cause poor, inefficient combustion, which increases the production of pollutants such as nitrogen oxide, carbon dioxide, and carbon monoxide. There is legitimate concern, therefore, about allowing gas with improper Btu limits to enter the pipeline system.

Poor combustion characteristics may also lower the efficiency of many gas-fired generation units, and this is an important issue for industrial firms and electric generators. When a sustained change in Btu content occurs, industrial and electric generators may be able to retune their combustion chambers adapt to the new gas quality. However, the tuning of combustion chambers and controls to a new gas quality level can be time consuming and the time spent in the tuning process may lead to a short-term loss in efficiency and/or product output. For these reasons, and more, even these large-scale consumers do not want to see rapid or continuously varying fluctuations in heat content, as that would have them constantly resetting their combustion chambers.

A second concern relative to gas quality is that potential liquid fallout from higher Btu gas degrades capacity performance and raises maintenance and safety issues. The main concern for pipelines is not strictly a varying level of heating content but the potential for liquid fallout within the pipeline system. Some of the higher-level hydrocarbon gases, pentanes and higher, will become liquids at lower pressure and temperature levels. A rapid pressure drawdown on the pipeline, perhaps due to a demand swing or a major pressure reduction at a valve, can cause this liquid fallout to occur. The presence of liquids in the pipeline can cause problems during compression, when delivering to customer facilities, and can also lead to corrosion if left to settle in low spots within the pipeline system for an extended period. Having liquids within the compressors degrades performance, as liquids are relatively incompressible as compared to gas. The degradation of performance is only part of the problem, however, as the back pressure from the liquids increases the stress on the compressor and that, in turn, can increase maintenance downtime and associated costs.

The potential for corrosion in the pipeline system is the more serious problem. Pipeline corrosion can lead to increased maintenance costs (related to attempts to locate and remove the liquids), removal of capacity from service, and, in severe cases, loss of system integrity. For this reason, pipelines need to specify within their tariffs the standards for monitoring the quality of gas volumes.

It should be clear from this discussion that the natural gas pipeline and storage industry provides more than a "commodity," as it is sometimes described. Rather, the natural gas transmission and distribution pipelines serving North America provide delivery services including the pressure, balancing, and gas quality necessary for the concurrent operation of millions of customers, from the largest industrial consumer to the flickering light of a backyard lantern. The pressure and balancing services are provided instantaneously, without direct requests from customers, and without regard to the actual time the molecules take to travel from the customers supply source.

4. Supply Challenges

a. Ethane Rejection

In the supply constrained case envisioned in this report, one potential mechanism to increase the heat (energy) content of the natural gas stream and to increase resultant delivery via the pipeline network is to reject ethane at the outlet (tailgate) of processing plants. This includes both ethane re-injection (or flashing) and lower ethane recovery during processing operations. Ethane has a higher heat content than methane, thus a gas stream with a higher level of ethane will contain more useable energy for consumers. Another favorable characteristic of ethane is that it is not subject to liquid fallout, as discussed above.

Although extensive use of ethane rejection will have to be carefully evaluated, it should be noted that ethane rejection has occurred numerous times in the past without significant problems. The previous rejections were the result of poor economics for ethane extraction, e.g. when feedstock prices for ethane dropped below the value of its equivalent heat content in the gas stream. According to published reports, ethane rejection during these past pricing periods has increased the overall heating content of the gas stream by an amount equivalent to 0.5 to 1.0 BCF/D of "regular" heat content gas. This adds appreciable energy delivery capability to the existing transmission system without requiring new pipeline infrastructure.

Given the higher prices projected for natural gas over the study period, it appears likely that it will be economic for processors to reject ethane throughout most of the analyzed period. According to reports (*Oil and Gas Journal*, April 21, 2003), the processing spread between NGL and natural gas prices has averaged below $0.11/gallon, less than the rate necessary for the development for new extraction plants. Since natural gas prices through 2025 are projected to average over $5.00/MMBtu as compared to $3.80/MMBtu (the Henry Hub Louisiana cash price from Natural Gas Week) for the last five years, the processing spread will be even lower, thus encouraging ethane rejection.

The ability of the ethane rejection process by itself to lower overall gas prices, however, is quite low. Even if an amount equal to 1.0 BCF/D of ethane was rejected, it would be only a fraction of total U.S. projected consumption of 73 BCF/D in 2010 and 85 BCF/D in 2020.

b. LNG Imports

Liquefied natural gas (LNG) imports will be an increasing source of supply in the study. Much of the LNG produced globally has a high ethane level. Due to high shipping costs, the world LNG market has developed with a focus on achieving the highest possible heat content per volume of liquid. For this reason, ethane was left in the gas stream prior to liquefaction. Since ethane liquefies at a temperature above methane, its inclusion did not markedly change the cost or design of the upstream liquefaction facilities.

The inclusion of ethane may result in an imported gas stream with Btu content per cubic foot above 1,100, the typical U.S. market area limit. Without treatment, such as nitrogen injection, processing, or blending with low-Btu domestic production, the ethane-rich LNG could be barred from the distribution and transmission systems in market regions. Recent work done under the auspices of the Gas Technology Institute indicates that LNG with a high ethane content does not appear to cause problems at the burner tip. This study is called "Gas Interchangeability Tests" and a draft of the first part of the study has been recently released. The initial results suggest that the Btu limits in practice throughout the industry are too narrow and that alternate indices, such as the Wobbe Index, are much more prescriptive of safe combustion. It is hoped that additional studies will help the industry determine not only what is "safe" but that they will also lead to true interchangeability standards to be incorporated in the pipeline and LDC tariffs.

Additional work in this regard must be done by the industry, but the results are encouraging and suggest that high-ethane, high-Btu LNG might be delivered in market areas without requiring substantial costs for blending or processing. It is hoped that additional studies will help the industry determine not only what is operationally appropriate but that they will also lead to true interchangeability standards, to be incorporated in the pipeline and LDC tariffs.

F. Maintenance Challenges for Infrastructure

1. Pipeline Safety Legislation

Besides operational challenges, pipeline transmission operators will have to focus significant capital and attention to maintenance of their systems over the next 25 years. In 2002, Congress passed the Pipeline Safety Improvement Act, which has major ramifications for the transmission industry. Besides improving the "one call" systems used by the states and requiring enhanced operator qualifications, the Act will cause enhanced maintenance programs and actual continuing inspections of all pipelines located in population centers. According to the Act's requirements, over 50% of the riskiest pipeline segments in these regions must be "physically" inspected in the next five years. The remaining facilities must be inspected during the following five years and all pipelines must be subsequently re-inspected at less than seven-year intervals. Though currently unaddressed, recovery of these costs will be of substantial concern to pipeline operators and the level of costs is of concern to ratepayers.

The inspection requirements of the Act will impact the industry in several different ways. First, the Act will lead to a marked increase in expenditures for pipeline testing. There are three major methods that can be used in integrity testing: Inline inspection using "smart pigs"; hydrostatic testing; and external inspection. Each method will have its own set of cost factors and these will vary per pipeline and region. For instance, many major long-haul pipelines built in the World War II era were not designed or constructed to be internally inspected on a routine basis, e.g. they can not easily be tested with recently developed smart pig technology. According to a recent study, "Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas" (Integrity Rule) by the Interstate Natural Gas Association of America (INGAA), 45% of the interstate grid will be difficult to test internally due to transitions in pipeline diameter, the occurrence of valves of different types and sizes, pipeline bends exceeding smart pig turning tolerance limits, etc.).

During a smart pig internal inspection, x-ray or electromagnetic detectors analyze the pipe from the inside for metal loss, cracks, and corrosion that could affect pipeline integrity. The detectors themselves are located inside of a cylinder, a "pig" that is inserted into the pipeline and pushed slowly through the system by the pressure of the natural gas. Although smart pigging has been used for a number of years to monitor pipelines, the Act will require its utilization on a much larger scale than previously.

Hydrostatic testing involves removing the pipeline from service, removing the natural gas, cleaning the pipeline of possible entrained liquids, and then filling the pipe with water under pressure. After the test is completed, the water must be removed and the pipeline dried to remove any water that could cause future corrosive damage.

The external inspection concept will require pipeline operators to remove the overfill of dirt covering the pipeline segment to be tested, which is frequently 6 feet in depth. The pipe is then inspected visually and with electromagnetic tools for cracks or corrosion. The pipeline must subsequently be reburied before being returned to full service. This method, of course, would have the maximum negative impact on landowners along the rights-of-way.

The cost of performing these tests is still being evaluated. The industry consensus, however, is that the tests will be costly. It is assumed, but not yet certain, that the FERC and other regulatory bodies will allow the cost of these tests to be included in pipeline tariffs. During periods of testing, it is clear that besides the direct cost of performing the inspection, an additional cost, or revenue loss, may occur from the reduction in throughput capacity as a result of these inspections.

The insertion of a smart pig or the excavations of a pipeline for external surveillance both reduce pipeline capacity due to pressure reductions during the inspection period. According to the Integrity Rule report from INGAA, a smart pig run in a pipeline designed for internal inspections will result in a 30% decline in throughput capacity for about three days. The capacity reduction for external inspection is 25% but the period of test climbs to 9 days. A hydrostatic test requires removal of 100% of the capacity and the process takes an average of 25 days due to the need to carefully purge the pipeline of natural gas, fill the pipeline with water, test the facility, and then dispose of water. (See Integrity Rule study, page 26.)

One effect of the increased inspections, therefore, will be temporary reduction in capacity on the lines being tested. The reduced capacity will result in an increased utilization factor for unaffected capacity and could result in a short-term increase in effective transportation rates. The result may thus be an increased short-term cost to consumers, even without the inclusion of expenses to physically perform the tests.

Many transmission laterals, however do not have an alternate line. INGAA found in the Integrity Rule study (page 12) that 85% of industrial and electric generation facilities had only a single connection. A capacity reduction or a complete removal of capacity could have an extremely harmful effect for these firms. Even if the pipeline capacity reduction is timed to occur during a period of scheduled plant maintenance, the costs can be substantial.

It appears that LDCs with multiple interstate connections will also be at economic risk from a reduction in service due to an integrity inspection. LDCs having multiple connections have sometimes designed their internal pipeline network to operate with specific pressure support from all interstate pipeline connections.

Thus during periods of interstate pipeline testing, the distribution pipeline capacity and compression capabilities within the LDC system may not be adequate to maintain full service without support from localized CNG trucks, LNG peaking storage, or propane-air injection facilities. Due to its focus on the interstate system, the Integrity Rule report did not attempt to calculate any cost impacts on LDCs for situations of this type.

INGAA found that integrity inspections will add an additional $6.8 billion to interstate pipeline transmission costs under the assumption of a ten-year testing cycle. By far the largest component of these costs will be due to short-term capacity reductions on the interstate grid, which is predicted to cost $5.7 billion. Capital expenditures on infrastructure improvements are estimated as $0.6 billion while inspection costs are estimated to be $0.4 billion.

Another result of the increased integrity activity could be a proactive decision by regulators to change historical regulatory policy to allow operators to build capacities slightly higher than current contractual commitments. The increased capacity could then be used to maintain normal throughput during periods when supplies are diverted from an alternate system due to maintenance. Since the Federal Energy Regulatory Commission (FERC), the oversight body of the interstate pipeline industry, does not routinely allow recovery of costs for capacity built without firm demand customers, this would probably require a change in current policy/ approach by FERC.

2. Abandonment of Facilities

An aspect of the industry that is associated with integrity inspection and maintenance is abandonment. This term refers to the removal from service of a pipeline or its appurtenance equipment, such as valves, meters and compressors. Abandonment occurs when a pipeline (or associated equipment) becomes so aged that it is no longer economically efficient to repair it. Instead, replacement of the equipment must be performed. Or, if producing wells have declined and a pipeline connection is no longer needed, facilities may need to be abandoned even though they are in proper working condition.

Abandonment thus may or may not be linked to the creation of replacement infrastructure. It should be noted, however, that even in the case of abandonment without replacement, the industry experiences costs and the need to allocate personnel to such activities. This is due to the requirement that the abandonment of facilities must be performed in an environmentally and operationally safe manner. While this rarely requires a transmission operator to physically remove a pipeline from the ground, it may require the removal of natural gas from a line and the insertion of concrete plugs to isolate the facility.

3. Impact of Rehab and Maintenance Outages

As stated in the section on pipeline safety, maintenance procedures reduce effective throughput capacity. For this reason transmission operators traditionally schedule maintenance activities during months of weaker demand, e.g. outside of the winter and summer peak consumption periods. By performing the maintenance in a low demand period, operators strive to keep remaining available capacity above that of projected demand. If maintenance uncovers a larger than expected problem or if a simultaneous need for unscheduled maintenance occurs, then capacity can be reduced below that needed even for a weaker demand period. If this happens, then the value of the remaining pipeline capacity may quickly increase. A potential solution would be if the industry had a means of reserving capacity for maintenance reductions, then pricing peaks or volatility might be reduced. In the current industry situation, however, a pipeline has this type of spare capacity only when it is not fully contracted. This leads to a conundrum in that a "popular" pipeline is the one most difficult to schedule and perform maintenance on and can be subject to price spikes and volatility.

4. Technology

Technology development was formerly funded in part through an industry surcharge. An area of growing concern within the pipeline transmission industry is the lack of funding for industry-related research and development (R&D). Because the industry as a whole has gone through a recent period of wrenching changes, internal funds for R&D are being severely restricted.

With expiration of the natural gas surcharge, the source of funds for future technology efforts is not clear. This resulting lower spending on R&D may negatively impact the industry and its ability to implement new technology over the next 25 years.

IV. Distribution

In the natural gas industry, the distribution system is defined as that portion of the gas delivery infrastructure that delivers gas from an interconnection point with the interstate pipeline system (the "citygate") to the ultimate, end-use customer.[5] Exceptions to this general definition are common, including the increasing number of electric generation plants that receive gas directly from an interstate pipeline. However, virtually all residential, commercial and most industrial customers receive their gas from a distribution system that is owned, operated and maintained by a Local Distribution Company (LDC). LDC does not refer to the type of ownership (investor owned or municipality). Rather, LDCs in this study means the entity that distributes gas to end-use customers.

A. Overview

As a general rule, LDCs broadly categorize their services into firm and interruptible deliveries. Distribution systems are designed to meet all firm customer demands for gas even under design (colder than normal) weather conditions. The demands of customers who are served with interruptible service may or may not be met under certain conditions as defined in the LDC's delivery tariffs, potentially during design weather conditions.

Because LDCs must design their distribution systems to deliver gas even under design weather conditions, the overall capacity utilization is much lower than that of interstate pipelines. For example, a residential customer who uses gas for heating, can have a peak wintertime monthly gas consumption that is 10 or more times what the same customer's monthly gas consumption will be in the summer. The difference in gas usage is even more pronounced if peak day to minimum use days are compared. Thus, customers with fuel oil backup, such as industrial consumers or electric generators, who can interrupt their gas usage by switching to an alternate fuel, have historically allowed the LDC to use its system efficiently and reduce costs to customers. For example, if an electric generating unit needs gas in the summer, an LDC will likely have room in its distribution system simply because the residential customers (taken as a group) have a lesser need for natural gas. At the other extreme, on a cold winter day, the residential customers need much more gas. If the electric generator can switch to an alternate fuel, the residential customers will have room for the gas they need to move through the distribution system. The greatest demands on a distribution system can arise when an electric generating unit uses natural gas at the same time the residential and commercial customers experience peak usage. Meeting these demands may require the LDC to expand its facilities, exacerbating its seasonal variance in capacity utilization and potentially increasing the total overall cost to serve customers.

B. Distribution Infrastructure Investment

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 main reinforcements, regulator replacement, regional de-bottlenecking, 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.

Construction of new facilities to meet customer demands requires the extension of gas mains and the construction of services to bring the gas into an individual home or business. The costs of both mains and services vary depending upon many factors. As shown in Table T-5, the Gas Technology Institute (GTI) has categorized the range of average costs for new construction based upon the area where the work occurs and the amount of developed versus undeveloped area.[6]

[5] This definition roughly follows the definition used to determine those segments of pipe that are regulated by the Federal Energy Regulatory Commission, i.e. transmission, and those regulated by others, i.e. distribution. Distribution regulation is typically provided by states or municipalities. This type of regulation covers pricing (rates) and terms of service. It should be noted that the Department of Transportation, which regulates the operation and safety of pipes, used a different definition.

[6] Nicholas Biederman, *Gas* "Distribution Industry Survey: Costs of Installation, Maintenance and Repair, and Operations" (September 2002), p. 6 & 35.

Similarly, the costs to install a new service average $460 in undeveloped areas, $1,400 in developed areas, and almost $5,600 in urban areas.

However, while there is substantial variation in costs for construction in specific areas, distribution facility costs for this study were aggregated and modeled on a nationwide average basis. Table T-6 shows the 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 expenses from a Gas Research Institute (GRI) study of LDC cost trends[7] and are refined based on the American Gas Association (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 industrial and electric utilities are connected directly to an interstate pipeline or that the project is funded through a customer specific charge. 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.

In addition to construction activities to expand the current distribution system, distribution systems are in a state of constant maintenance and upgrade to maintain safety, ensure system reliability and to minimize future maintenance costs. Based on AGA benchmarking information, replacement of mains ranged from 0.4 to 0.7% per year of existing installed mains among surveyed LDCs. Service replacements ranged between

[7] Gas Research Institute, *Historical Cost Trends and Current Regulatory Initiatives in the Local Gas Distribution Industry*, May 1999.

	Customer Density (customer per mile of main)						
	Urban	**Urban**	**Mixed**	**Mixed**	**Suburban**	**Suburban**	**Rural**
Percent of main under pavement	45-65%	65-100%	0-44%	45-64%	0-44%	45-64%	0-44%
Percent of new main installed in undeveloped areas	51%	7%	60%	78%	85%	60%	78%
Proportion of new main installed in common trench with other utilities, %	52%	32%	n/s*	32%	34%	n/s	9%
Average new main cost, $/ft	14.5	n/s*	n/s*	9.85	9.90	9.95	2.80

*n/s means there is insufficient data to determine an average value.

Table T-5. New Pipe Construction in Different Service Areas

	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

Table T-6. Distribution Facility Costs for New Customers in 1997

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-7. Assumed Footage of Mains 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

Table T-8. Other Facilities per New Customer

0.6% and 1.3% per year among surveyed LDCs. Thus, for this study, main replacements were assumed at 0.5% per year and service replacement at 0.75% per year. These rates imply service lives beyond 25 years. This matches the current projections for the lives of materials used to build new distribution facilities. As a result, in this study, main and service replacements occur only for distribution facilities installed before 2002. The facilities built in this study are not replaced during the study.

In addition, steel and cast iron pipe tend to require more maintenance and replacement. As of 2000, according to DOT RSPA reports, there was a total of 524,616 miles of steel and 24,083 miles of cast-iron greater than 4-inch diameter. The reports indicate that 11.6% of the steel pipe is bare-unprotected, 3.8% is coated-unprotected, 2.7% is bare-protected and 81.9% is coated-protected.

Given current technology, some current main replacements and upgrades can be completed by insertion of plastic piping into existing cast iron and steel pipe, which may allow for higher pressures and increased throughput. System upgrades accomplish the same results. Also, directional boring allows pipes to be installed without digging a trench.

Despite the use of cost saving techniques, main and service replacements often are significantly more costly than the construction of new facilities. Frequently, replacements occur in congested public right-of-ways where numerous other underground facilities are located. Also, replacements often occur in developed urban or suburban areas where pavement restoration and landscaping or lawn restoration is required. (By contrast, new construction often occurs in relatively undeveloped areas where these concerns are not as common. See Table T-5.) Thus, based on AGA benchmarking studies, main replacement costs were assumed to cost 50% more than construction of new mains. Similarly, replacement of services was assumed to cost 25% more than the cost of new construction. Finally, meter replacement was assumed to cost 15% more than new construction.

The total annual facility investment requirements for distribution companies are similar in the Reactive Path and Balanced Future scenarios. To accommodate the demand projected in the Balanced Future scenario, the results from the distribution analysis show that total annual facility investment requirements for distribution companies will average $5.3 billion per year (2002 dollars),[8] with a cumulative investment from 2004 through 2025 of $135 billion. This compares to average annual expenditures during the 1990s, which averaged slightly more than $4.8 billion.

However, funding for this level of expansion may be more difficult than in the 1990s because more of an LDC's cash flow in the future will be needed for other purposes, including buying higher priced gas and placing it in storage. This may result in a greater need to finance expansion of the distribution systems with

[8] Required investment reported in constant 2000 dollars.

external funds than was the case in the 1990s. LDC access to capital markets will, therefore, be important but, given appropriate regulatory policy, should not be a constraint.

In determining the costs to expand the distribution system, a 1% per year increase in productivity was assumed. This significantly lowers the projected costs. Given appropriate funding for research and development (R&D), achieving increased productivity seems reasonable. Thus, it is not expected that adequacy of the distribution infrastructure will be a constraint in the future.

The improvement in overall efficiency in the residential sector in the Balanced Future reduces system throughput slightly, resulting in a modest decline in required mains reinforcement and delayed replacements. The decline in power generation demand also reduces the required investment to serve new load. This decline in investment is, however, offset by a small increase in investment to serve growth in the commercial and industrial sector load, as the lower natural gas prices in the Balanced Future scenario result in some additional growth in commercial and industrial demand.

As discussed in the Transmission section of this chapter, the United States Congress passed legislation intended to enhance the safety of "transmission" type gas pipelines[9] through stricter inspection requirements. The U.S. Department of Transportation (DOT) is currently developing the rules to implement the legislation. Companies are required to perform a baseline inspection within the first ten years of all "transmission" like pipeline located within a high consequence area (HCA). Re-inspection will be required every seven years after the initial inspection.

The AGA estimates the LDCs operate almost 22,000 miles of pipeline that is subject to this new pipeline integrity program. While the exact requirements mandated by the DOT, is not known, AGA has estimated the cost of compliance for LDCs at $2.7 billion to $4.7 billion (2002 dollars) over the next 20 years. For purposes of this study, a cost of $16,000/mile or $3.5 billion was assumed. Data on the breakdown of costs between capital investments versus maintenance expenditures is not yet available from the industry. Similarly, information on the pattern of these future expenditures was not available. Thus, for this study, it was assumed that 60% of these expenditures will be incurred in the initial ten-year period, when baseline inspections must occur. Historical annual capital expenditures in 1998 dollars can be seen in Figure T-16.

For the remainder of the study period, costs to comply with the pipeline integrity program will continue. However, since facilities needed to complete the inspections will have already been built, integrity management plans will have been written, and HCA will have been identified and mapped, it is anticipated that costs to comply with the pipeline integrity program will decline. Offsetting this decline will be the increased amount of pipe included in the pipeline integrity program as LDCs expand their systems. Thus, annual costs for LDCs to comply with pipeline integrity standards in years after 2012 were assumed to be 40% of the annual costs of the initial period. In summary, from 2004 through 2013, an annual cost of $250 million was assumed to meet the pipeline integrity standards. From 2014 through 2025, an annual cost of $100 million was assumed.

In addition to pipeline integrity costs, LDCs face increased costs to protect against security threats by terrorists. These costs cannot be readily quantified. As part of outreach, a limited number of LDCs indicated that LDCs expect some increase in costs compared to historical trends, but overall increases that are less than the costs to comply with new pipeline integrity standards. If these costs represent a 1% increase in the costs to maintain and expand the gas distribution systems, LDCs would incur new expense of $48 million per year. These costs are included here only for reference and were not included in the figures shown in this section.

C. Challenges to Building and Maintaining the Required Distribution Infrastructure

1. Provider of Last Resort/Supplier of Last Resort

As the LDC marketplace has evolved, the requirements for serving customers have continued but roles have changed. All states that have residential and commercial choice programs have addressed the provider of last resort (POLR) or supplier of last resort (SOLR)

[9] The DOT definition of "transmission" differs from the definition used by the rate setting regulators like the FERC. As a result, LDCs operate a significant amount of "transmission" pipelines from a DOT perspective.

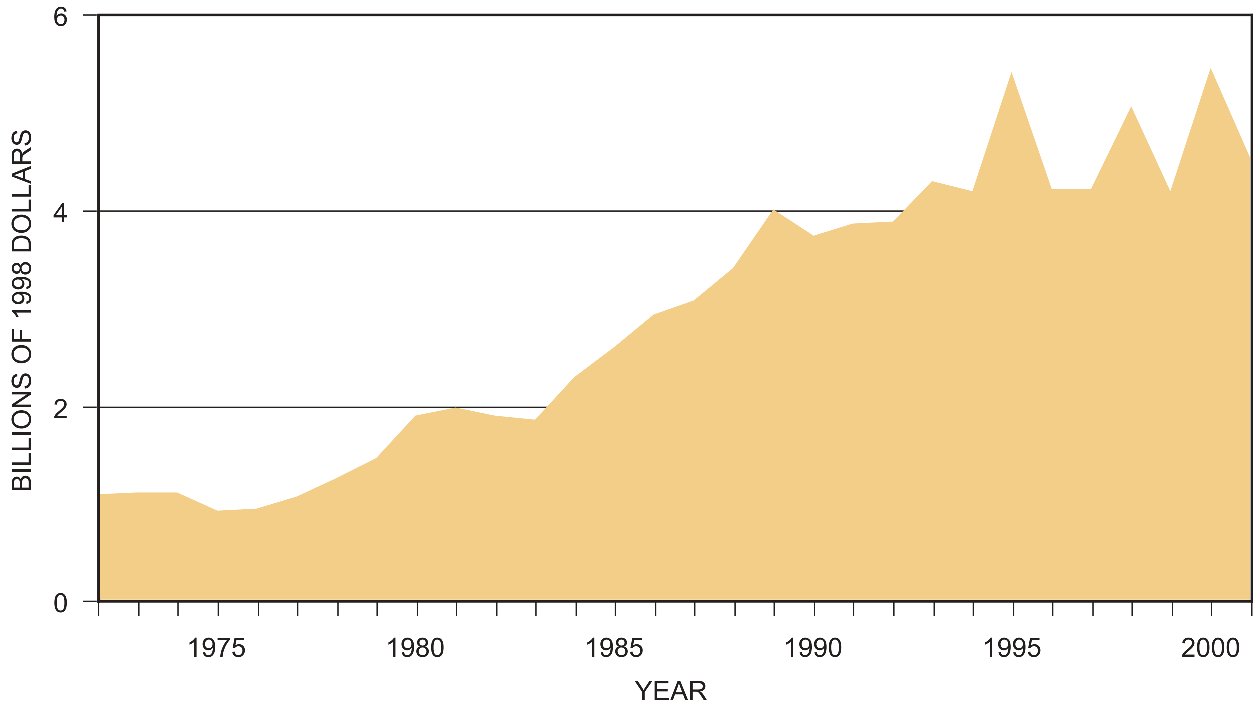

Figure T-16. Historical Investment in Distribution Infrastructure

issue to some extent. The POLR/SOLR responsibility has been defined in varying ways, but generally is the responsibility to assure that small gas consumers will not experience an interruption in the supply of natural gas to meet their needs. Thus, POLR/SOLR can include the responsibility to provide essential needs customers with gas if the customer's supplier goes bankrupt or fails to deliver gas for other reasons. POLR/SOLR responsibility always includes small volume residential gas customers (residential or commercial) and seldom, if ever, includes very large customers like electric generators.

There is debate about what entity should be a POLR/SOLR. Some states have required that the LDC assume this role, while other states have prohibited the LDC from holding the role. While these policy debates will continue, it is important to recognize that the demand for natural gas to serve residential and commercial markets will likely continue to grow. In fact, this study projects the number of residential customers served by the natural gas industry will grow from 61 million in 2003 to 81 million in 2025. This level of growth will necessitate that state and federal policy makers work with the various industry participants to assure that interstate pipeline and storage capacity is available to serve future customers. Clear definition of the responsibilities of the POLR/SOLR and appropriate commitments from policy makers to allow critical expansions are required to assure reliable service to customers.

Specifically, state regulators need to:

- Clarify the role and responsibility of the POLR/SOLR
- Define who holds that role
- Support appropriate contracting practices to assure that natural gas services and infrastructure are available to meet customer demand.

2. Siting and Permitting

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. Many of these issues have been discussed at some length in the Transmission section of this volume. It is worth noting here, however, that access to public right-of-way (ROW) within metropolitan regions is becoming more difficult to obtain and more expensive. For example, some states and municipalities are prohibiting the installation of gas distribution facilities in a highway or street ROW. Local zoning can also impact the location of facilities and their cost. Increased costs from such items are not included in this study. However, governmental bodies need to consider the impacts (financial as well as safety and reliability) of added restrictions on the installation and maintenance of distribution facilities.

To address these and other concerns, states should also develop a mechanism to coordinate siting issues among affected state and local governmental entities, wherever multiple governmental entities have an impact on the siting of LDC facilities. Using the NARUC/IOGCC Pipeline Siting Work Group Report[10] as a framework, each state should consider, as needed, programs that might include the following type of initiatives:

- The governor establishing within the office of the governor a coordinating effort to organize and expedite the activities of all state and local natural gas permitting entities.
- States naming a lead agency that would have the authority to monitor processing schedules within existing regulatory requirements.
- The state economic development office (Commerce Department) being involved with the coordination effort and recommending actions to streamline the process.

Coordination and certainty in completing a permitting process are keys to meeting the growing need for natural gas while balancing many other key issues. Consistent government policy and rapid, predictable regulatory decisions are needed to enable timely and cost-effective system expansions.

The business environment in which LDCs operate has changed dramatically since the 1999 NPC study. Traditionally LDCs provided gas to all customers served by the distribution system. Beginning in the 1980s, large customers have had the option of purchasing their own gas and simply transporting it on the LDC's system. During the 1990s, increasing numbers of small use customers, including residential customers began to choose alternate suppliers and use the distribution system simply to transport the gas. (See Figure T-17.) Based on programs that are currently operational or announced, 99% of all electric utility customers and 96% of all industrial customers will have customer choice. Additionally, at least 72% of all commercial customers and 57% of all residential customers will also have the option to choose their gas supplier.[11] This continuing transition has changed the decision processes related to their system expansions.

3. Access to Investment Capital

Another topic of concern to LDCs arises because the reduced gas usage resulting from customer-achieved efficiency gains will lead to less gas flowing in an LDC's system and its current asset base to serve existing customers. Most LDCs have experienced this phenomena throughout the 1990s. This normally means that expansion capital will be required to attach new customers just to maintain system throughput and the associated revenue levels. Actual growth in throughput and revenue will require additional capital investment, beyond the level described, just to keep even with customers' conservation efforts. Previous expansions have largely been financed through internal cash generated from the business; however, forecasts suggest that capital markets will need to provide more of the capital required to maintain and grow the throughput and associated revenues. Accessing capital at the lowest cost in the competitive markets requires a compelling story. To achieve favorable access to capital, traditional rate designs may need to be modified or augmented to reflect the adverse impact to the financial health of LDCs caused by customers achieving the desirable goal of greater efficiency. One such example is the State of Oregon recently implementing a "conservation" tariff that encourages greater conservation by customers while mitigating the potentially adverse impacts of reductions in LDC revenue.

To serve the natural gas needs of customers through 2025 will require substantial investments by LDCs.

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10 Philip N. Asprodites, "Roadmap to Implementation of the Final Report of the Interstate Oil and Gas Compact Commission/National Association of Regulatory Utility Commissioners Pipeline Work Group in Louisiana" (April 2003).

11 AGA, Policy Analysis Issues, Issue Brief 2002-02, May 7, 2002.

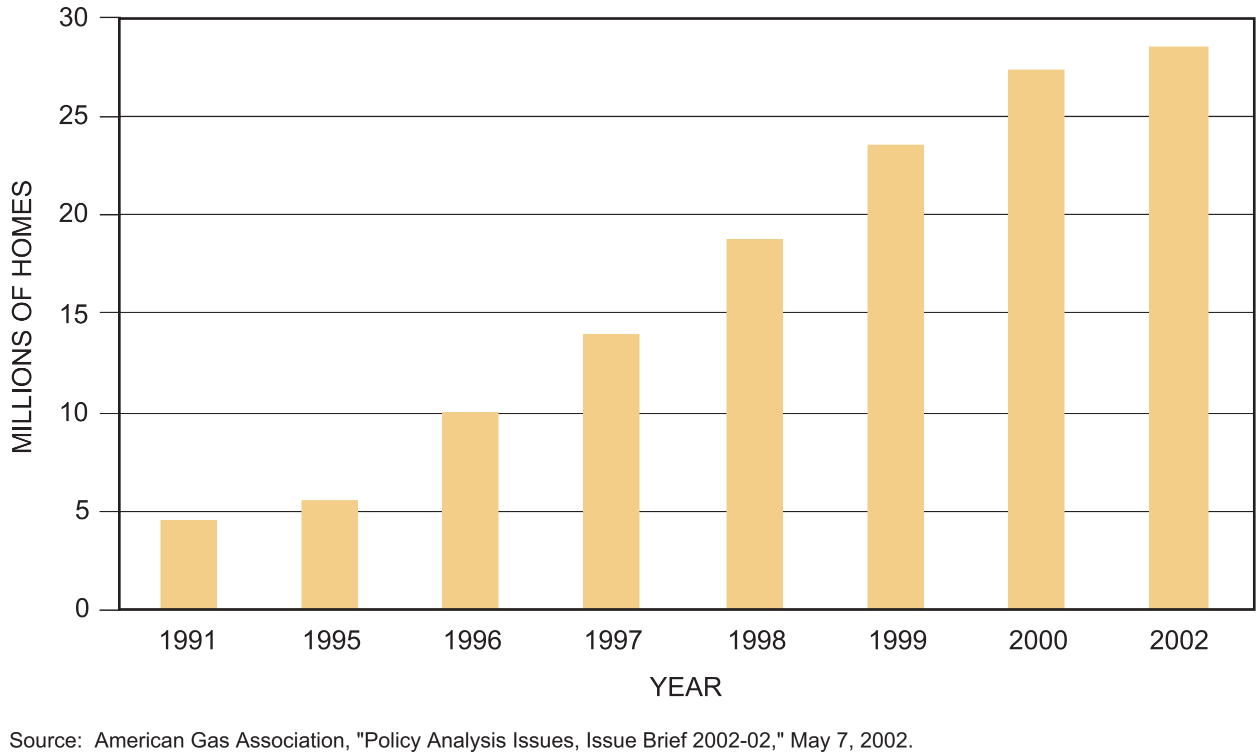


Figure T-17. Residential Customer Choice Program Announcement (Cumulative Number of Homes Eligible)

These investments are within the range of historical spending levels. However, investments of this magnitude require appropriate access to the capital markets (both debt and equity markets). Access to the capital markets will only be possible if the financial health of all parts of the gas distribution industry remain healthy.

The reliable, safe, efficient delivery of natural gas is critical to the health of the American economy. Natural gas usage, as a percentage of energy usage in the American economy, has grown steadily. Yet, LDCs are a relatively small part of the capital markets. LDC working capital needs will expand significantly at the gas prices suggested by the NPC analysis. Currently, the United States is considered to have adequate gas in storage if more than 2.5 TCF has been stored at the beginning of the heating season. The carrying cost to store this gas at $6.00/MMBtu is significantly more than the comparable costs in the $2 to $3 gas price environment often seen in the 1990s.

These types of changes, as well as changes in the broader energy market, are impacting the business risks faced by LDCs. Constant attention to the financial health of the distribution industry will allow adequate access to capital markets for all future expansions needed to serve customers.

D. Reliable Gas Service in a Changing Market

Reliability in providing gas service to customers has been the hallmark of the natural gas industry. As the natural gas marketplace changes, new demands are placed on the interstate pipeline, storage and distribution system infrastructure. Customers are demanding new services to meet their needs. In particular, electric generating customers can dramatically change the demands for gas as they follow electric load. The changes in gas requirements can occur very quickly. The issues arise whether considering the increased number of large gas-fired electric generating units or a very large increase in the amount of distributed generation in the future.

Because electricity cannot be stored, it must be produced at the moment it is used. Thus, electric generating unit requirements for natural gas can vary dramatically from hour to hour as they follow the demand for electricity. Also, the customer demand for electricity reaches a peak in the summer in many areas of the country. Thus, power plants are increasingly consuming larger amounts of gas; at the same time, distribution companies and others are attempting to fill their seasonal storage in preparation for the heating season. For example, aquifer storage fields (see detailed discussion in the Storage section) have traditionally been designed to fill in the summer and withdraw in the winter on a very specific, scheduled basis. Electric generation may require a pipeline operator to attempt multiple injections and withdrawals, greatly complicating the use of aquifer storage fields. Also, as the use of gas to generate electricity in the winter increases, further peak-day demands are placed on the natural gas infrastructure.

These concerns have been the subject of considerable discussion and debate among industry participants. Recently, INGAA,[12] AGA[13] and the APGA[14] developed a framework to discuss these issues.[15] The group's stated goal is to "ensure the continuation of the historic reliability of the natural gas industry as gas demand grows, particularly from the power generation sector." These evolving discussions among industry and government will need to continue to assure adequate, reliable, cost-effective natural gas service to all customers in the natural gas marketplace.

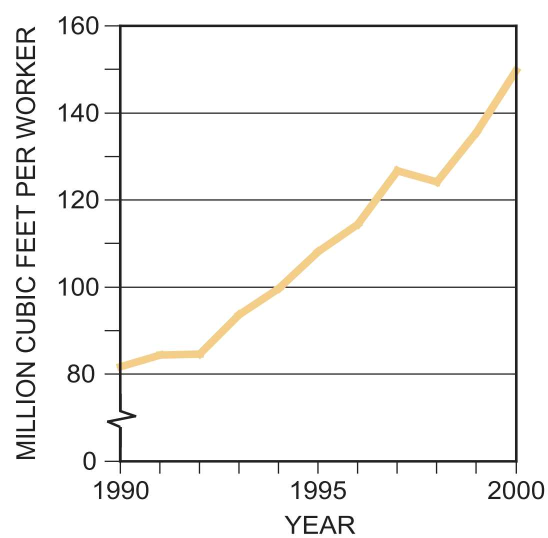
E. Productivity Improvements Require R&D Investments

Since 1990, the productivity of distribution companies has steadily improved. This improvement resulted from: changes in the work practices resulting from continuous-improvement type programs; reductions in the workforce with judicious use of contracted labor; and implementation of new technologies affecting all aspects of construction, maintenance and operation of gas distribution systems.

A measure of productivity in LDC operations is gas delivered per LDC employee. With an average drop in staffing levels of 4% per year since 1990, Figure T-18 demonstrates the increased amount of gas delivered per distribution company employee, primarily as a result of implementation of new technologies. Much of this technology came from research and its correlated product and skill-set developments. However, expenditures for gas research have declined in the last five years, driven in large part by the reduction in funds collected through the FERC-mandated gas distribution surcharge. The collections of these funds will be completely eliminated by the end of 2004.

As noted above, these reductions were in part achieved by using contracted labor, i.e. outsourcing. Some future levels of reductions in the workforce are likely. However, the ability to continue work force reductions at these historical rates through the study period without degrading customer service and safety is unlikely.

In the 1999 NPC Natural Gas Study, an annual 1% productivity assumption was used. For comparison to other studies, in its 2001 Baseline Projection the Gas Research Institute projected a 2.1% decrease in the cost of distributing a unit of gas. (See Figure T-19.)



Sources: Energy Information Administration, *Historical Natural Gas Annual, 1930 Through 2000*, DOE/EIA-E-0110(00), December 2001, Table 3, "Natural Gas Consumption in the United States, 1930-2000"; American Gas Association, *Gas Facts*, various editions.

Figure T-18. Gas Delivered per Worker

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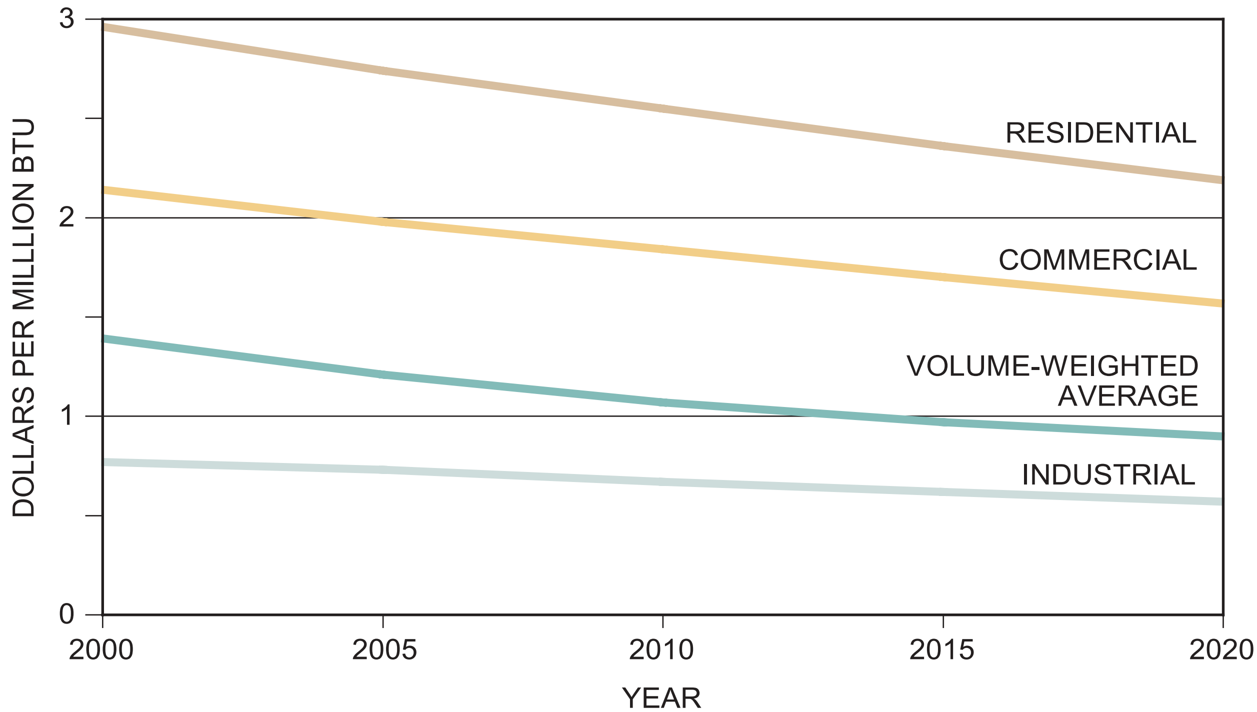
12 INGAA (Interstate Natural Gas Association of America) represents interstate pipelines.

13 AGA (American Gas Association) represents investor-owned local distribution companies.

14 APGA (American Public Gas Association) represents publicly owned natural gas local distribution companies.

15 March 7, 2003, Letter to The Honorable Patrick H. Wood, III, Chairman of FERC from David N. Parker, President and CEO of the AGA.



Source: Gas Research Institute, *Baseline Projection Data Book, Volume II*, 2001 Edition, March 2001.

Figure T-19. Gas Distribution Costs (1999$)

It is reasonable to assume that half of this savings would result from enhanced technology and half from business practice improvements. Given the workforce reductions of the last ten years, the rate of further reductions is problematic. Thus, a 1% gain in productivity is likely a reasonable assumption for this study, but only if technological advances can be supported. Such a gain would result in reduced customer costs of $300 to $400 million per year, over the costs of the previous year. Offsetting some of this improvement, however, will be the costs of implementing the pipeline safety requirements and integrity rules previously discussed.

The need for research is as strong now as in the past. The ability to monitor and maintain the existing distribution infrastructure continues. With the level of expansion projected to meet the new demands shown in this study, new and even more environmentally sensitive and lower-cost construction techniques are needed. Better technologies for locating existing underground facilities will enhance the safety and operation of existing facilities[16] and reduce the costs of new construction. Improved operation of existing facilities with increased flexibility and throughput will reduce costs. Research and development have provided and must continue to provide the new techniques and technologies to reduce costs and increase both the safety and reliability of distribution systems.

Many LDCs believe government funding of research remains a critical need. In addition to state- and federal-sponsored R&D, many LDCs participate in and fund R&D. However, some distribution companies may operate under regulatory frameworks that discourage R&D. In such situations, LDC shareholders, finding themselves at risk to benefit, may be reluctant to support investment in the research and development that is needed to continue these productivity enhancements into the future. While funding for gas research must be assured, the funding

[16] "Third party damage," where someone other than an LDC hits the distribution pipe, is the leading cause of damage to the distribution system.

must be provided by those who benefit from the research. Given the inability of LDC shareholders to benefit from R&D investments in operations, the intervention of government will be required. State regulatory commissions should consider removing any barriers to LDCs' participation in collaborative research. Similarly, DOE funding of gas utilization technology research must continue and, if possible, expand.

F. Distributed Generation

In its broadest sense, distributed generation (DG) is the production of electricity near the place where the electricity is used, often on the customer's premises. DG can use many energy forms to produce electricity, including wind, solar and natural gas. In analyzing the impacts on the gas distribution system, however, only natural gas units will be considered. It is important to recognize that in recent years, large DG units have tended to be connected directly to pipelines. Thus, only smaller DG units will likely be served directly from a local distribution system. For purposes of this discussion, small DG will mean units that will produce 20 megawatts at peak, or less.

DG can be used in settings where a high level of electric reliability is required or where a heat recovery opportunity exists that greatly enhances the efficiency of the DG application. Customer interest in installing DG is growing and has moved into the mainstream of energy planning. Considerable research is being focused on the development of distributed generation. Added research is critical.

In addition, policy makers and standards organizations are assessing steps that will facilitate the increased use of DG. For example, the Federal Regulatory Energy Commission (FERC) has initiated an advance rulemaking notice to determine the interconnection requirements for DG units.[17] The National Association of Regulatory Utility Commissioners has developed Model Interconnection Procedures.[18] While not yet consensus standards, these do provide a basis for policy debate. Also, the State of New York has developed interconnection standards for small DG units.[19] The Institute of Electrical and Electronics Engineers (IEEE) recently developed standards for DG interconnections. The IEEE standard (P1547) establishes minimum technical and performance standards for interconnecting DG up to 10 megawatts. Development of these types of standards to resolve technical and business practice issues is moving forward and will need to continue if DG is to play a major role.

An increase in DG penetration in the marketplace will not dramatically impact the supply, demand or transmission assumptions of this study. Electrical demand for the nation is not going to change simply because of changes in the manner in which the electrical demand is met. Thus, to the extent that DG usage increases beyond the model assumptions, electricity generation in other electrical power plants will be reduced. To the extent that DG is operated as baseload facilities, there may also be additional displacement of baseload sources, including coal or nuclear generation.

However, the differences, when considered on a North American scale, are minor. In this study, DG penetration on the distribution system as a whole was not significant. Should DG become more prevalent, LDCs will be required to transport more gas through their systems. If DG installations occur in areas where gas demand has declined because of conservation, efficiencies, or business relocations, only minimal changes in distribution infrastructure may be needed. In areas where gas usage is already approaching infrastructure design limits, there may be an increase in cost by requiring larger sized pipes, higher pressures or both. The following comparisons will help to gain a feel for the impacts of these potential increases in DG usage. These assume an installation in the Great Lakes Region:

- A moderate size commercial establishment (e.g. a drugstore) with a 30 KW DG unit will increase gas consumption by the equivalent of approximately 25 residential homes.

[17] Advanced Notice of Proposed Rulemaking, August 16, 2002, RM02-12-000 Standardization of Small Generator Interconnection Agreements and Procedures.

[18] Small Generation Resource Interconnection Procedures for Resources No Larger than 20 Megawatts.

[19] Standardized Interconnection Requirements and Application Process for New Distributed Generators 300 kVA or Less, or Farm Waste Generators 400 kW or less, Connected in Parallel with Radial Distribution Lines, New York State Public Service Commission, Revised March 20, 2003.

- A 120-room hotel with a swimming pool and a 60 KW DG unit will increase gas consumption by the equivalent of approximately 50 residential homes.
- A 3 KW DG unit installed in a single residential home will increase gas consumption by the equivalent of approximately 3 average residential homes.

Thus, while extensive modeling of DG within the NPC study did not occur, it is important that policy makers continue to provide opportunities for customers to receive the advantages of DG, while balancing issues like reliable service and cost. DG can provide advantages in reliability, energy efficiency and environmental impacts, when encouraged by appropriate public policies. With DG development in its infancy, industry and government must work together to define its role and potential contribution to the future. This includes dialogs with respect to:

- Appropriate tax policy including tax credits and depreciation
- Resolving lingering interconnection issues between the DG unit and the electric grid to assure safety and reliability
- Research funding to further develop DG technologies

Businesses should encourage the expansion and installation of distributed generation through their support in:

- Resolving technical issues regarding the safety, reliability and interconnectability of DG units
- Educating consumers on the advantages and limitations of DG
- Funding of initiatives to bring DG technologies into the market.

V. Storage

The ability to effectively store and retrieve large quantities of natural gas has been a key factor in the growth and development of the natural gas industry. At its most basic level, the storage function allows for the generally asynchronous supply and demand functions to be efficiently matched. Perhaps the most obvious example of this functionality involves satisfying the highly seasonal demand for natural gas for space heating purposes in the residential and commercial sectors during the wintertime. Indeed, without the ability to build gas inventories in storage prior to the high-demand winter period; it is unlikely that natural gas would have become such a dominant space-heating fuel in these sectors. Without storage, the wintertime surge in demand would require that production be accelerated greatly for the winter season, then throttled back as temperature-driven demand waned. Huge amounts of pipeline capacity would have to be available to transport the gas to market areas, much of which would then be vastly underutilized at other times of the year. Thus, a major function of storage is to augment supply to satisfy seasonal demand increases.

A second major function of storage is the operational function of load balancing, usually associated with pipeline operations. In essence, the function of load balancing is operating the system in such a way that receipts of gas into the system roughly equal deliveries of gas from the system, within certain operating tolerances. Thus, interconnections to storage give the pipeline operator a place to inject excess gas when more is being received by the pipeline than delivered, as well as an incremental source for withdrawal of gas when more is being delivered to customers than is received by the pipeline.

A third major function for storage, which has gradually grown in prominence, is the rapid cycling or turnover of working gas storage inventory. This has been driven both by the deregulation of natural gas wellhead prices and transportation infrastructure, and also by changes in the electricity-generating industry. Further, this function involves the physical capabilities of certain types of storage facilities and is most often associated with salt cavern storage facilities because of the ability to inject gas into and withdraw gas from these facilities at very fast rates relative to their storage capacities (see "Characteristics of Major Storage Types," later in this section). This function gives the holder of this type of storage capacity significant flexibility. Operationally, it enables the industry to accommodate the frequent load fluctuations characteristic of natural-gas fired electricity generating facilities, which have comprised the bulk of newly-installed generating capacity as the electric industry deregulates. This function also supports a wide variety of market-based uses, where the purpose of its use is primarily to obtain a profit as opposed to operational uses. Essentially, this function enables participants to profit from changes in gas prices over short time intervals, taking advantage of periods of high volatility in gas markets.

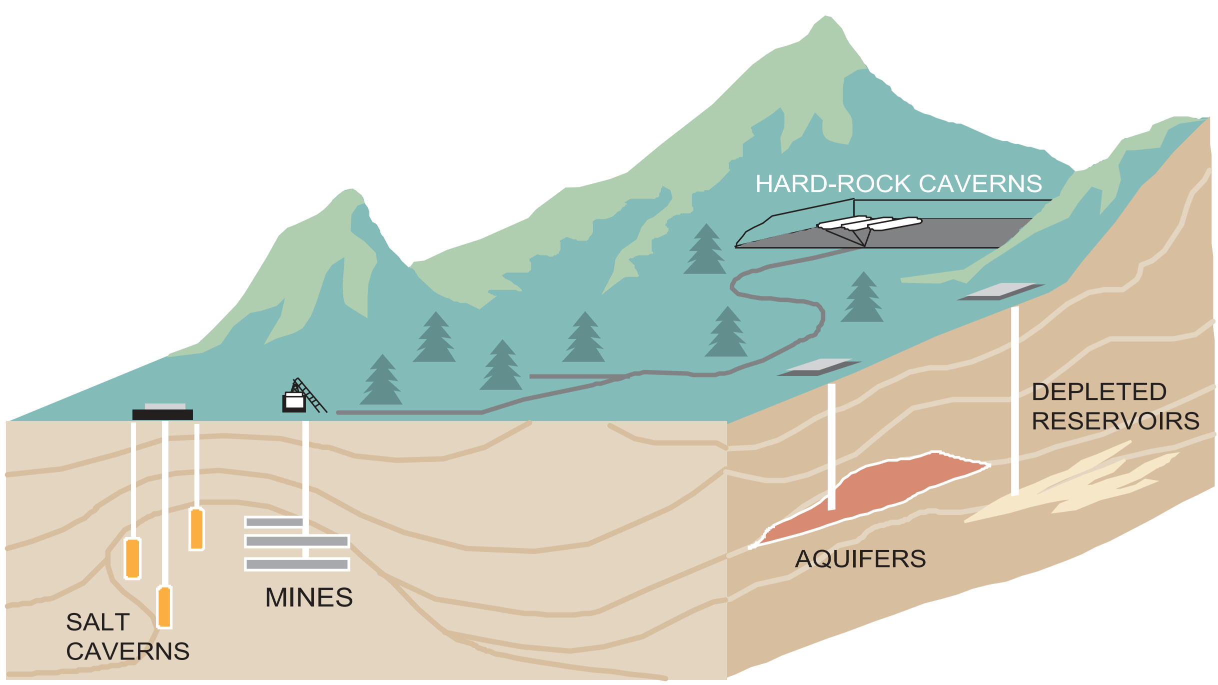
A. Overview

Natural gas may be stored in a number of different ways (see Figure T-20). It is most commonly held in inventory underground under pressure, in three types of facilities. These are depleted oil and/or gas reservoirs, aquifers, and caverns developed in salt formations. Several reconditioned mines are also in use as gas storage facilities.

Each type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation costs, deliverability rates, cycling capability), which govern its suitability to particular applications. Two of the most important characteristics of an underground storage reservoir are its capability to hold natural gas for future use and the rate at which gas inventory can be injected and withdrawn – its deliverability rate. The distribution of storage facilities varies regionally by type within the U.S. lower-48 and Canada, as can be seen in Table T-9.

It is important to note that while this data indicates total working gas capacity of over 4.5 TCF, the largest amount of inventory actually cycled in any year has been 2.9 TCF, and evidence suggests that storage capacity may be incapable, for a variety of reasons, of cycling more than that volume without extreme seasonal price variability.

In addition to the three primary storage types, industry participants also have a number of other options to satisfy the temporary spikes in demand generated by end users – such as a surge in demand for space heating during an unusually cold period, or a sudden requirement for an electric utility to bring online a natural gas-fired generator – that can exceed the ability of traditional storage to handle. These storage options usually involve storing liquefied natural gas (LNG), compressed natural gas (CNG), or liquefied petroleum gas (usually propane) in above-ground storage tanks, and have the capability to deliver natural gas or a propane-air mix into the local distribution system when required. These facilities are generally capable of relatively high deliverability but for short durations. (Commonly used storage terminology is defined in the box entitled "Common Terms of Storage Measurement.")



Source: PB - KBB, Inc.

Figure T-20. Types of Underground Natural Gas Storage Facilities

Region/State	Depleted Gas/Oil Fields		Aquifer Storage		Salt Cavern Storage		Total		
	Number of Sites	Working Gas Capacity (BCF)	Number of Sites	Working Gas Capacity (BCF)	Number of Sites	Working Gas Capacity (BCF)	Number of Sites	Working Gas Capacity (BCF)	Percent of Working Gas Capacity
Consuming East	242	1,722	34	354	4	5	280	2,081	46
Consuming West	31	606	6	38	0	0	37	644	14
Producing	74	1,087	*	*	24	138	98	1,226	27
Total U.S. Lower-48	**346**	**3,414**	**41**	**393**	**28**	**143**	**415**	**3,951**	**87**
Canada	11	598	0	0	1	4	12	602	13
Total North America	**357**	**4,012**	**41**	**393**	**29**	**147**	**427**	**4,553**	**100**

*Any aquifer facilities in this region have been counted as depleted gas/oil fields to preserve data confidentiality.

Notes: Regions are those used by the EIA in its Weekly Underground Storage Survey. BCF = billion cubic feet.

Table T-9. Regional Distribution of Storage Facilities and Working Gas Capacity

1. Characteristics of Major Storage Types

The following are brief descriptions of the characteristics of each of the major storage types. Depleted oil/gas reservoir storage facilities are the most widely distributed geographically. Aquifer facilities are found primarily in the Midwest, while most salt cavern storage has been developed in the salt formations along or near the Gulf of Mexico in Texas, Louisiana, and Mississippi.

a. Depleted Oil and Gas Reservoirs

Most existing gas storage in the United States is held in depleted natural gas or oil fields. Conversion of a field from production to storage may take advantage of existing wells, gathering systems, and pipeline connections. The geology and producing characteristics of a depleted field are also well known due to its previous production history. All oil and gas reservoirs share similar characteristics in that they are composed of rock with enough porosity so that hydrocarbons can accumulate in the pores in the rock, and they have a less permeable layer of rock above the hydrocarbon-bearing stratum. Operators thus use the pressure of the stored gas and, in some cases water infiltration pressure, to drive withdrawal operations.

Cycling in this type of facility (number of times a year the total working gas volume may be injected/withdrawn per year) is relatively low, and daily deliverability rates are dependent on the degree of rock porosity and permeability. These facilities are usually designed for one injection and withdrawal cycle per year, and often for only one cycle. Daily deliverability rates from depleted fields vary widely because of differences in the surface facilities (such as compressors), base gas levels, and the fluid flow characteristics of each reservoir. Retention capability, which is the degree to which stored gas is contained within the boundaries of the reservoir area, is the highest of the three principal types of underground storage. Depleted field storage is also the least expensive to develop, operate, and maintain. However, base gas costs, for providing a minimum reservoir pressure, can be quite significant.

Common Terms of Storage Measurement

There are several volumetric measures used to quantify the fundamental characteristics of an underground storage facility and the gas contained within it. For some of these measures, it is important to distinguish between the characteristic of a facility such as its *capacity*, and the characteristic of the gas within the facility such as the actual *inventory level* or the actual rate at which gas is injected or withdrawn. These measures are as follows:

Total gas storage capacity is the maximum volume of gas that can be stored in an underground storage facility by design and is determined by the physical characteristics of the reservoir and installed equipment.

Total gas in storage is the volume of storage in the underground facility at a particular time.

Base gas (or **cushion gas**) is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. For depleted field and aquifer storage facilities, base gas typically occupies one-half or more of total storage capacity, with the remaining capacity available to store working gas.

Working gas capacity refers to total gas storage capacity minus base gas.

Working gas is the volume of gas in the reservoir above the level of base gas. Working gas is available to the marketplace.

Deliverability is most often expressed as a measure of the amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. Also referred to as the deliverability rate, withdrawal rate, or withdrawal capacity, deliverability is usually expressed in terms of millions of cubic feet per day (MMCF/D). Occasionally, deliverability is expressed in terms of equivalent heat content of the gas withdrawn from the facility, most often in dekatherms per day (a therm is roughly equivalent to 100 cubic feet of natural gas; a dekatherm is the equivalent of about one thousand cubic feet, or 1 MCF). The deliverability of a given storage facility is variable, and depends on factors such as the amount of gas in the reservoir at any particular time, the pressure within the reservoir, compression capability available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the total amount of gas in the reservoir: it is at its highest when the reservoir is most full and declines as working gas is withdrawn.

Injection capacity (or **rate**) is the complement of the deliverability or withdrawal rate – it is the amount of gas that can be injected into a storage facility on a daily basis. As with deliverability, injection capacity is usually expressed in MMCF/D, although dekatherms per day is also used. The injection capacity of a storage facility is also variable, and is dependent on factors comparable to those that determine deliverability. By contrast, the injection rate varies inversely with the total amount of gas in storage: it is at its lowest when the reservoir is most full and increases as working gas is withdrawn.

These measures for any given storage facility are not necessarily absolute and are subject to change or interpretation. For example, in practice, a storage facility may be able to exceed certificated total capacity in some circumstances by exceeding certain operational parameters. Additionally, the distinction between base gas and working gas is to some extent arbitrary; so gas within a facility is sometimes reclassified from one category to the other. Further, storage facilities can withdraw base gas for supply to market during times of particularly heavy demand, although by definition, this gas is not intended for that use.

b. Aquifers

Aquifers, which originally contained water, may be suitable for gas storage purposes if certain geologic criteria are met. In the United States, aquifers that are used for gas storage are found primarily in the Midwest. There are several reasons why an aquifer is the least desirable type of underground storage, many of which contribute to making aquifer storage more expensive to develop and maintain than depleted reservoir storage. It is typically not as expensive to develop as salt formation storage, however.

First, it takes about twice as long to develop an aquifer storage site compared with an average depleted gas or oil field. Unlike a depleted site, the geology of an aquifer site is unknown beforehand. As a result, seismic testing must be performed to determine its geologic profile. Important also are such characteristics as the confinement area of the reservoir, the location and type of the "cap" rock ceiling barrier, existing reservoir pressure, and the porosity and permeability of the reservoir rock. The potential gas capacity of the reservoir is also unknown and can only be determined as the site is developed.

Second, all new facilities must be installed, including wells, pipelines, dehydration facilities, and compressor operations. Aquifer storage sites also may require additional facilities relative to the average depleted field site, such as greater compression for injection purposes (to push back the water), or more extensive dehydration facilities to "dry out" the gas upon withdrawal.

Third, no native gas is present in an aquifer formation. Thus, base or cushion gas must be acquired and injected into the reservoir to build and maintain deliverability pressure. Once in operation, aquifer reservoirs have one potential advantage over depleted field storage. Because of the additional support of an aquifer's water (pressure) drive, in most instances, higher sustained deliverability rates than gas or oil reservoirs can be designed and attained. Aquifer formations have certain operational characteristics that distinguish them from other storage types. Injection and withdrawal activities generally are required to conform to a disciplined schedule to avoid damage to the reservoirs or loss of gas. Therefore, aquifers only cycle once per year.

These limitations have important market implications, because operations at these facilities can't respond significantly to price changes or demand fluctuations. Thus, aquifer storage is more suitable for seasonal use and not suitable for multiple cycling and rapid response to changing needs, supply fluctuations, or sudden price arbitrage opportunities.

c. Salt Caverns

There are two basic types of geologic formations in which cavern structures used to store natural gas are developed: salt domes and bedded salts. Both are created by injecting water (leaching) into a salt formation and shaping a cavern. Caverns created in salt domes are large caverns as they are constructed within very thick salt formations. Salt domes can be miles in diameter, 30,000 feet in height, and can be as shallow as several hundreds of feet below the surface. Storage caverns developed in salt domes are often shaped roughly like a thick carrot: relatively "tall" and narrow.

While the salt dome itself might extend thousands of feet into the earth, storage caverns in salt domes are generally limited to depths shallower than 6,000 feet. This is because, at extreme depths, as temperature and pressure increases, salt is ductile and will creep or flow, which can become a major consideration in cavern construction possibly leading to excessive cavern closure/degradation over time. Hence, the optimum size of a storage cavern in a salt dome must be established with this in mind.

A bedded salt storage cavern, on the other hand, is generally developed from a much thinner salt formation (hundreds of feet or less). As a result, the height-to-width ratio of the leached cavern in a bedded deposit is much less than for a cavern in a salt dome. The depth of bedded salt formations is highly variable in North America. Some bedded salt formations are as shallow as a few hundred feet while others are many thousands of feet deep. Bedded salt formations also contain much higher amounts of insoluble particles (shale and anhydrite rock) than salt dome formations. These materials remain in the reservoir after the leaching process and can impact the eventual capacity of the cavern. In addition, because the height/width ratio is low, the cavern roof can be less stable than in a domal cavern. As a result of these as well as other factors, bedded salt storage development and operation can be more expensive than that of salt dome storage.

Because salt cavern storage facilities are essentially high-pressure storage vessels akin to underground tanks, their injection and withdrawal rates are very high and base gas requirements low. Their resulting ability to cycle working gas inventory numerous times during a year makes them ideal for meeting large demand swings.

d. LNG Storage

Liquefied natural gas (LNG) is natural gas that has been cooled to approximately minus 260 degrees Fahrenheit for storage as a liquid. LNG storage accounts for a very small portion of the overall natural gas storage capability in the United States as LNG working gas storage capacity is just over 2% of the overall capacity.[20] However, LNG storage facilities have relatively high deliverability rates that allow operators to deliver an amount equal to up to 14% of all underground storage. LNG storage can be grouped in two general categories: peak-shaving storage and marine terminals. Each of these categories has specific characteristics and utilization benefits.

Traditionally, LNG storage facilities in the United States were constructed solely for use by local utilities but more recently they have been developed to provide input into interstate pipelines. Peak-shaving LNG facilities fulfill an important role in supplying natural gas to customers. Unlike marine terminals which cycle their inventory, peak-shaving LNG storage is usually filled and held in the cold, liquid state for an extended period of time to supply natural gas only during peak demand periods. Peak-shaving LNG storage is often located in areas where it is not feasible or economical to access more traditional storage or pipeline infrastructure.

Peak-shaving LNG storage has two main positive attributes: its high deliverability capability as compared to more traditional storage and its flexibility with respect to where the storage can be located. However, peak-shaving LNG storage is more costly on the basis of dollars per million cubic feet of storage capacity, when compared to traditional storage.

Marine import terminals receive LNG shipments and have on-site storage. The LNG is stored in aboveground storage tanks until it can be regasified and injected into the pipeline grid. Additionally, the LNG can be stored until it is trucked, in liquid state, directly to customers. Marine terminals are typically equipped with enough storage space to accommodate LNG receipts from one to two LNG tankers. The principal operation of an import terminal is not for gas storage, but rather for receiving the water-borne LNG imports and then promptly regasifying LNG for shipment via pipelines to customers.[21] Marine terminal storage may also provide some peak-shaving storage services; however, that is not its principal function.

LNG marine terminal operators work to achieve a stable offtake rate. Terminal planning typically aims for a regular arrival of tankers, with adequate on-site storage to adapt to slight variations in shipping schedule. Delays in tanker receipts can be accommodated by drawing stocks from on-site storage; similarly, early arrival of shipments leads to some buildup in stocks. Operators must balance ship arrivals and inventory to ensure their ability to meet contractual requirements, so falling below certain operational thresholds is perceived as undesirable. However, there tends to be some flexibility in operations that might allow increased flows during periods of peak demand to help mitigate the market stress. In the forecast analyses herein, it is assumed that current and future LNG marine terminal operators can increase their overall sendout from each facility to 120% of normal flow rates for up to 3 days. This higher rate of drawdown must be followed by subsequent refill to restore on-hand stocks to optimal conditions. Operators will attempt to refill such stocks as promptly as possible.

e. Propane-Air

Propane-air storage is another method by which gas utilities and industrial customers meet demand during the coldest days of the year. Propane is stored in aboveground tanks or underground caverns (usually granite) until needed. Because it vaporizes relatively easily, propane can enter the gas pipeline distribution systems with little difficulty. However, as a gas, propane is heavier and has a higher energy density than methane, which is the largest component of natural gas. While propane contains about 2,520 Btu per cubic foot, natural gas contains approximately 1,000 Btu per cubic foot. As a result, these plants blend propane with air to produce a gas that has a burning characteristic similar to natural gas. Generally, a propane-air mixture containing 1,400 Btu per cubic foot has burning characteristics similar to natural gas. Some industrial consumers who utilize interruptible service on pipelines may use propane-air as a back-up fuel capability when their gas

[20] Source: Energy Information Administration, *U.S. LNG Markets and Uses*, January 2003.

[21] Ibid.

capability is "interrupted" by their utility. Similar to LNG plants, propane-air systems also provide utilities an opportunity to meet peak demands without reserving pipeline capacity that would rarely be needed. Although propane-air systems are common as a cheap alternative to pipeline capacity, there have been concerns over several failures for the propane to properly vaporize on especially cold days in the Midwest.

f. Compressed Natural Gas

Utilities across the country also may compress natural gas for local storage, although this technology is used to a much lesser extent than propane-air and LNG. Natural gas, which is transported on interstate pipelines at a pressure anywhere from 600 to 1,500 pounds per square inch, is compressed to approximately 3,000 pounds per square inch for storage in large cylinders. These compressed natural gas (CNG) cylinders, ranging 30-50 feet in length and approximately 20-inches in diameter, can be used as a form of peak shaving, but are more often used for vehicular fuel.

The cylinders are also often trucked to system locations to provide standby service where gas utilities are repairing gas distribution lines and don't want to interrupt service to local consumers. Although CNG continues to grow as a vehicular fuel, compression of natural gas for peak-shaving operations is expensive in comparison to LNG and propane-air because of its relatively low energy density.

2. Geographic Distribution of Storage Assets in the United States

The locations of the active underground natural gas storage facilities in the U.S. lower-48 and Canada are displayed in Table T-10. The regional grouping of states in Table T-9 was developed by the American Gas Association for use in its now-discontinued weekly underground natural gas storage report. (The Energy Information Administration has adopted the same regional breakout for its weekly survey and report of underground natural gas storage inventories.) A summary of the numbers of storage facilities and estimated working gas capacities by type of facility and region is also presented in Table T-9.

B. Historical Background and Statistics

In 1915, natural gas was first successfully stored underground in Welland County, Ontario, Canada. Several wells in a partially depleted gas field were reconditioned. Subsequently, gas was injected into the reservoir and withdrawn the following winter. In the United States, in 1916, Iroquois Gas Company placed

U.S. LOWER-48

New England	Mid-Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Mountain	Pacific
ME	NJ	MD	MI	KY	ND	OK	MT	WA
VT	NY	DC	WI	TN	SD	TX	ID	OR
NH	PA	WV	OH	MS	MN	AR	WY	CA
MA		VA	IL	AL	NE	LA	NV	
CT		NC	IN		IA		UT, CO	
RI		SC			KA		AZ, NM	
		GA			MO			
		FL						

CANADA

Eastern Canada	Western Canada
Quebec	Manitoba
Ontario	Saskatchewan
	Alberta
	British Columbia

Table T-10. Locations of North American Storage Facilities the Zoar field, south of Buffalo, New York, into operation as a storage site. In 1919, the Central Kentucky Natural Gas Company repressurized the depleted Menifee gas field in Kentucky. By 1930, nine storage reservoirs in six different states were in operation with a total capacity of about 18 billion cubic feet (BCF). Before 1950, essentially all gas storage was in partially or fully depleted gas reservoirs.

In some areas of the country, particularly the Midwest, there were no suitable depleted gas/oil fields available for potential conversion to storage fields. As a result, the concept of using an aquifer formation for storage was tested and developed. Although the testing was done in the 1930s, it was not until the early 1950s that firms began to develop aquifers for natural gas storage.

Most of the nation's storage sites were developed between 1955 and the early 1980s. During this period, U.S. storage capacity increased over fourfold, from about 2.1 trillion cubic feet (TCF) in 1955 to 8 TCF in 1985.[22] The need for underground storage grew as consumption of natural gas increased significantly. The mix and requirements of consumers also changed as demand shifted toward the more weather-sensitive residential and commercial markets. Furthermore, in the mid- and late-1970s, the interstate market encountered supply and demand imbalance situations during several exceptionally cold winters, and as a result service curtailments were imposed.

The demonstrated inability of the industry to meet large and sudden increases in demand for natural gas during the winter months in some areas helped stimulate the planning and construction of new storage. Regulators and industry saw increased storage development as necessary to avoid a repeat of such occurrences and also to satisfy expected increases in gas demand during the 1980s. Since the mid-1980s, total storage capacity has remained at approximately 8 TCF, even with the recent surge in new storage development as some new sites have been added but some have also been abandoned. However, the daily deliverability from storage has increased.

The volatile gas market during the late 1980s set in motion certain events that heightened interest in new storage facility development. Interest in new storage resurged as regulatory changes under FERC Orders 436 and 636 forced more competition into the marketplace. Storage became increasingly important as all pipeline services were unbundled and customers had to make their own storage arrangements. These changes led to increased interest in development of storage sites that would provide greater deliverability and more access to working gas capacity. Between 1992 and 2002, deliverability from storage increased by 29%, from approximately 65 BCF/D to 83 BCF/D.

C. Results from the Study Regarding Capacity Utilization

1. Changes in Storage Capacity

The reference case (Reactive Path scenario) analysis projects an increased demand for North American storage capacity of close to 1 TCF over the 22-year study period, relative to the demands on storage in the 1999-2002 period, which averaged 2.3 TCF per year. Recognizing that the base period (1999-2002) was characterized by relatively light demand on storage due to generally warm winters, it is estimated that the current storage infrastructure is sufficient to satisfy an increased average annual demand of approximately 300 BCF, leaving 700 BCF of demand that will need to be met by development of new capacity. As much as 150 BCF of this new capacity could be required in the very near term if there were a return to winter weather patterns closer to historical normal levels. As only 109 BCF of storage additions are projected to occur by 2005 (based on projects currently announced), most of any such near term demand increase will need to be met through more efficient use of existing capacity, and measures to increase capacity and deliverability at existing facilities.

By 2015, total cumulative storage capacity additions will need to have approached 400 BCF, and by 2025, 700 BCF, to accommodate growth in the total gas market. While many of the best resources for gas storage (based on location and geology) have been developed, this rate of growth in the infrastructure is considered achievable provided that favorable market conditions exist to finance the additions. Conventional storage is expected to account for over 80% of the projected additions and high deliverability peak shaving the remainder. The states or provinces included in each region are identified in Table T-10.

When discussing the adequacy of storage infrastructure, it must be kept in mind that demands on storage

[22] Refers to total storage capacity rather than usable capacity.

vary greatly, from year to year, depending on weather, and that even if the projected growth in capacity is achieved there will likely be winters when the system is unable to fully supply gas withdrawal requirements without some significant short-term reduction in gas demand, whether price induced or otherwise. A winter of significantly colder than normal winter weather can increase demand for storage capacity by as much as 25% relative to a normal year. It has been many years since North American storage capacity has been tested by such a winter and it is very likely that current storage capacity would be severely challenged to meet such demand, with potential for even greater price spikes and demand destruction than what was experienced in 2001 and 2003.

Storage additions for the U.S. lower-48 were evaluated on the basis of nodes within the nine census regions, while additions for Canada were split between nodes in eastern and western Canada.

In the U.S. lower-48, the need for near-term storage additions is greatest in the Pacific, East South Central, South Atlantic, West South Central, and Mid-Atlantic regions. Near-term storage additions for the Mountain region are projected to grow modestly. No near-term storage additions are projected for the West North Central or New England regions.

Projected additions to peak shaving and conventional North American storage over the 2005-2025 period are 550 BCF. Nearly 80 BCF of the projected additions are for high deliverability peak shaving storage facilities, with lower-48 additions accounting for 90% of this requirement. All regions of North America will require some new high deliverability peak shaving storage. The need for this type of storage will be greatest in the South and Mid-Atlantic regions, collectively accounting for over 30% of the projected growth in peaking storage, driven primarily by growth in the residential and commercial sectors. Peak shaving growth in the West South Central and Pacific regions are projected to grow at 9 BCF each. Eastern Canada will experience the need for peak shaving additions as well; additions in this region are projected to be over 8 BCF.

Projected additions to conventional storage during 2005-2025 are largely concentrated in the lower-48 market area. Three regions in particular, East North Central, Mid-Atlantic, and South Atlantic, are projected to experience significant storage growth amounting to about two-thirds of the projected overall storage additions. Combined storage growth in these three regions is projected to be about 320 BCF, with the greatest additions to the East North Central at approximately 111 BCF (10% increase over current), followed by nearly 109 BCF (44% increase over current) and 99 BCF (23% increase over current) to the Mid-Atlantic and South Atlantic, respectively.

This increase in storage will require additional pipeline capacity to reach the market centers, particularly for storage developed to serve the Mid-Atlantic and Northeast markets, which lack suitable reservoirs for storage development within the region. Instead, the new storage capacity will have to be developed in the western portions of Pennsylvania and New York and eastern Ohio. This will result in the construction of incremental pipeline capacity of approximately 2 BCF/D from these storage sites to the coastal market centers, which include New York City, Boston, and Philadelphia.

The Mountain region is projected to require nearly 55 BCF of additional storage (17% growth), and the West North Central a proximal 37 BCF (22% growth) of new storage capacity. Eastern Canada is projected to see growth of about 40 BCF, or about a 20% increase relative to current storage capacity.

2. Changes in Storage/Withdrawal Patterns

Annual average North American daily loads adjusted for storage are projected to grow 19 BCF/D from 71 BCF/D to 90 BCF/D from 2005-2025 (Figure T-21). This growth will impact storage injection and withdrawal patterns in certain regions more than others, though in general, seasonal withdrawals will increase in response to growth in the residential and commercial sectors, and to some extent growth in power generation. In contrast, growth in the Industrial sector during this same period is projected to be virtually flat with likely no impact on storage usage patterns. Injection patterns will be impacted more due to growth in power generation than anything else.

Daily loads during the 10 highest demand days of the year are projected to increase from approximately 101 BCF/D to over 126 BCF/D during the study period, while loads during the 60 highest demand days are projected to grow from 92 BCF/D to 116 BCF/D. Storage plays a critical role in satisfying incremental load during peak use periods. The highest load periods occur during the heating season and

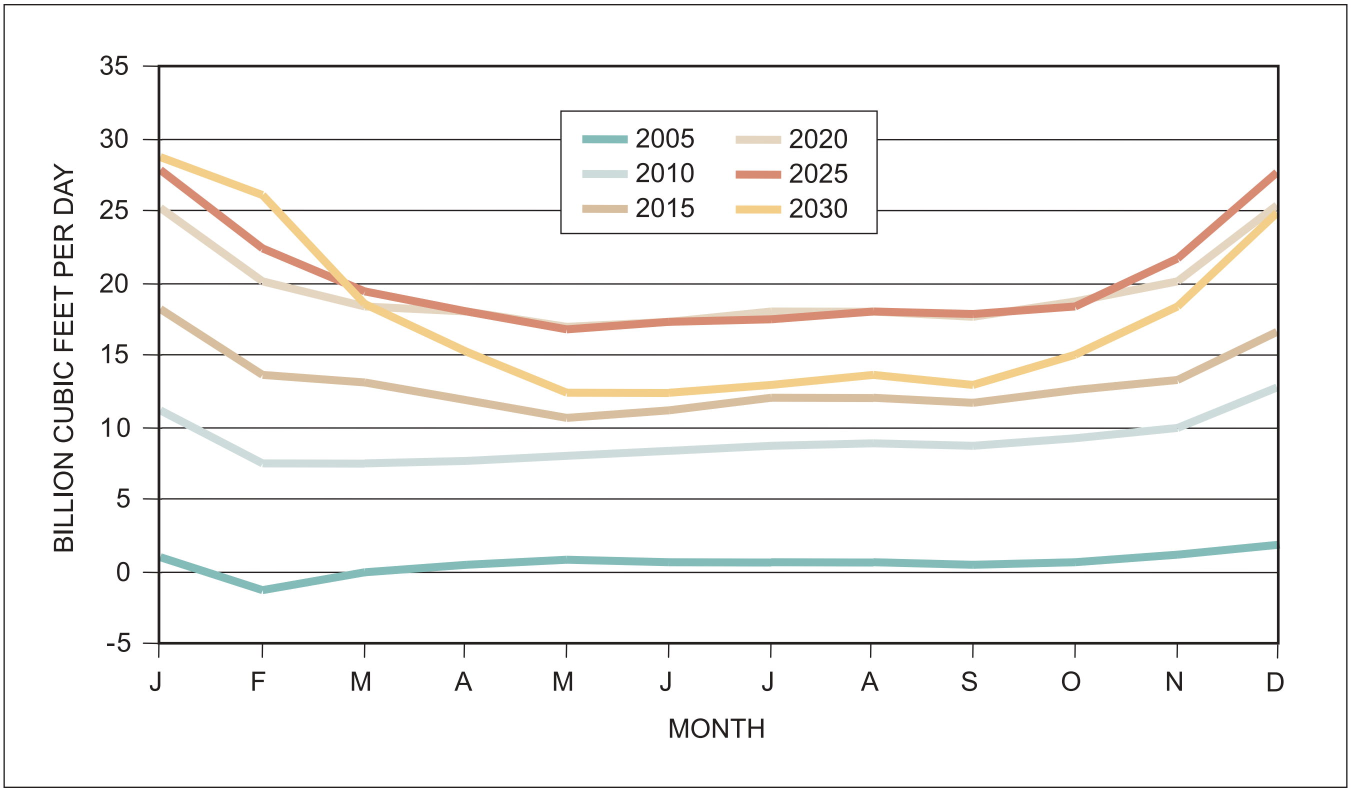


Figure T-21. Growth in Monthly Gas Demand (from Base Year 2003)

storage withdrawals typically satisfy over 50% of the daily North American load during the highest demand days of the heating season. Two regions in particular stand out in this regard: in the East North Central region, the reference case projects demand during the 60 highest demand days of the year will be over 2.4 times the average daily load. A similar projection is evident for the West North Central where demand during the 60 highest demand days of the year is nearly twice that of the average daily demand. Under such circumstances, storage is ideally suited to satisfy these incremental seasonal loads, which are predominantly driven by space heating requirements in the residential and commercial sector.

Loads associated with the residential/commercial sectors are highly temperature sensitive, and thus, significantly impact winter withdrawals, and will continue to do so. North American growth in these two consumption sectors is projected at 18% and 52% respectively. The impact of this growth will result in greater utilization of existing storage capacity – i.e. withdrawing a larger percentage of working gas capacity than has been experienced in recent years – and create the need for new storage facilities on a regional basis.

As previously noted, overall growth in the natural gas market is expected to require the addition of approximately 400 BCF of new storage working gas capacity by 2015 to meet the needs of a year of normal weather. However, actual annual storage injections and withdrawals have been highly variable in the past, due primarily to variability in weather, and in particular the magnitude of winter heating degree days. The potential impact on demand for storage due to future weather variability was assessed by reference to the weather sensitivity cases developed by the Demand Task Group. Those cases mapped actual historical data for heating degree days and cooling degree days by census region for the period 1977 through 1999 onto the forecast period, varying the timing of the coldest year data (1978-79).

The results of the weather sensitivity analysis indicate that annual demand for storage capacity should be expected to be highly variable if year-to-year weather variability is comparable to the historical period. Figure T-22 illustrates this annual variability in demand for storage under three of the weather sensitivities, relative to the base case which assumes normal weather in every year. It indicates that in the event of a significantly colder than normal winter in the near

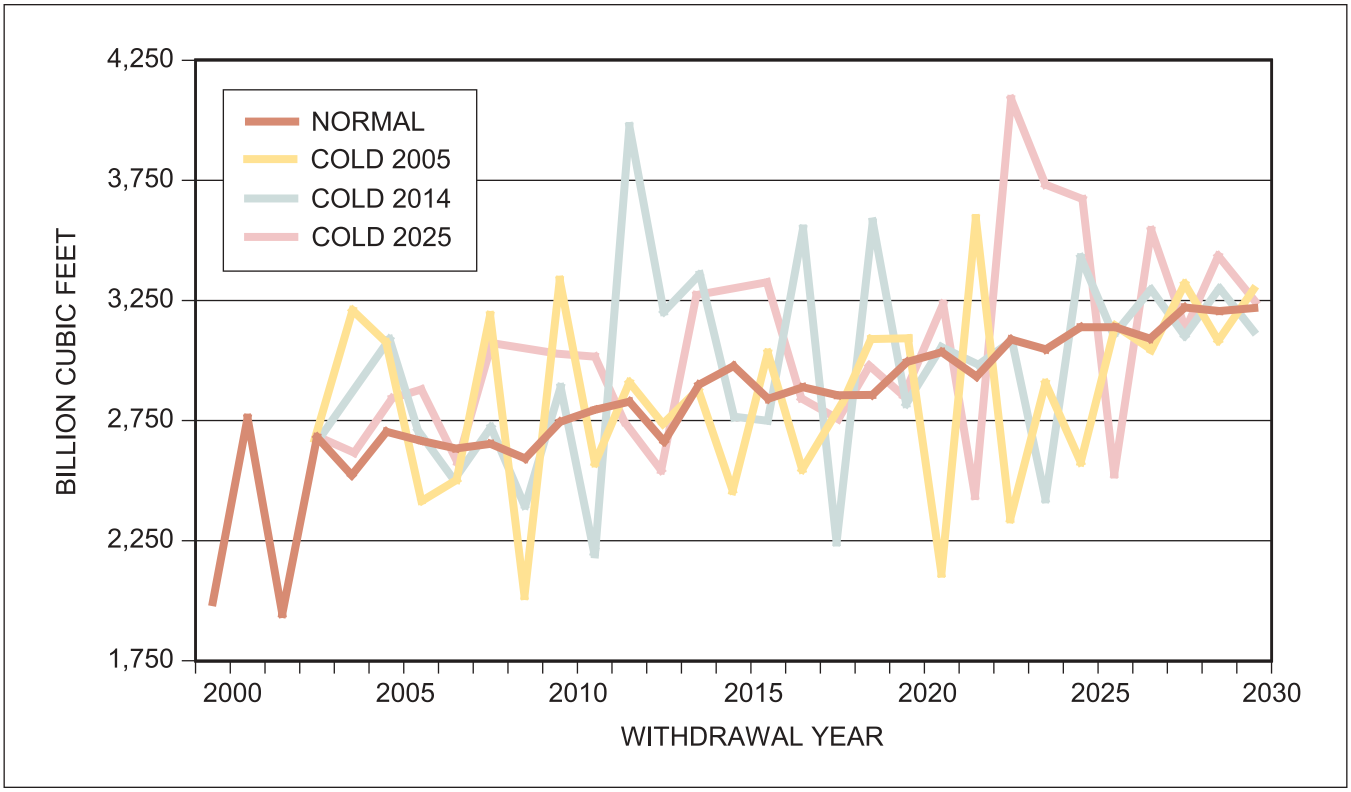


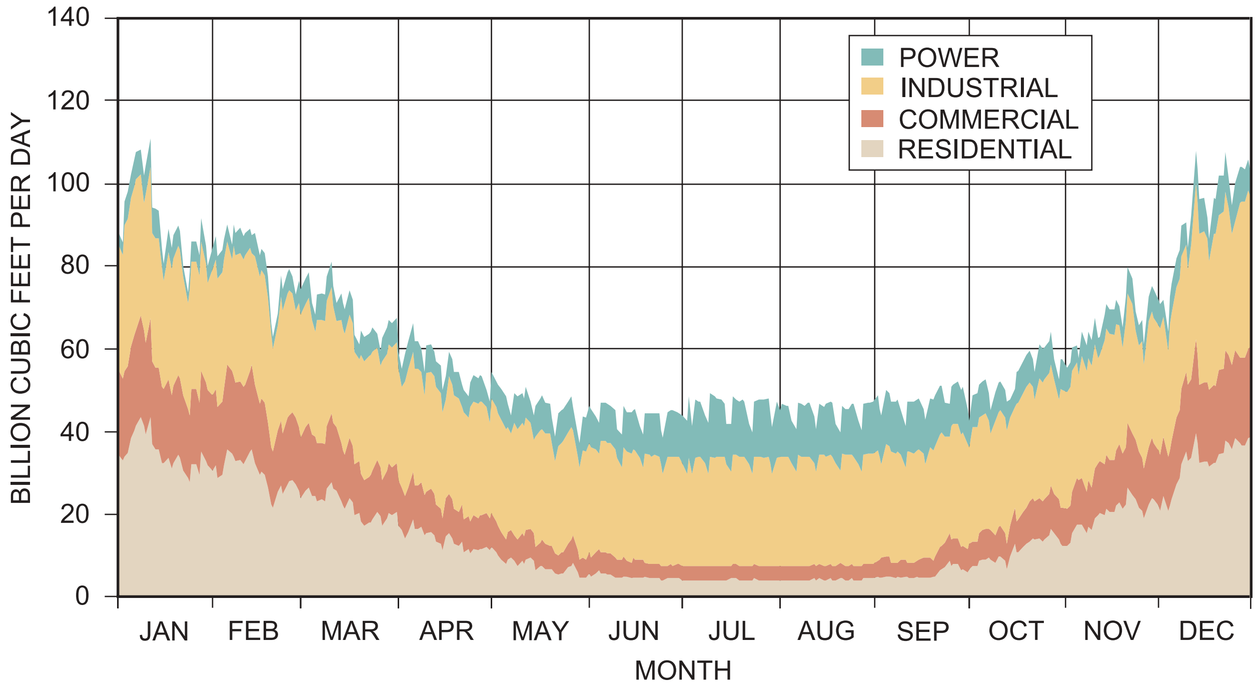
Figure T-22. Total North American Storage Demand in the Balanced Future Scenario – Normal vs. Cold Weather

term, demand for storage could be as high as 3.2 TCF, as compared to maximum annual net storage injections and withdrawals to date of 2.9 TCF. Peaks in demand for storage could be more extreme in the event that such a colder than normal winter occurs in later years, due to the combined effect of the weather and the growing weather sensitivity of gas demand during the forecast period.

The ability of existing U.S. and Canadian storage infrastructure to achieve total summer injections or total winter withdrawals of more than 2.9 TCF per year has not been demonstrated, and years in which more than 2.6 TCF to 2.7 TCF have been injected and withdrawn have tended to be characterized by high levels of gas price volatility. Winter peak gas demands in excess of the current infrastructure's capability would likely result in increased gas price peaks, seasonal fuel switching and seasonal demand destruction.

Natural gas demand has always been seasonal, but a recent phenomenon is that, due to increased gas-fired generation implemented around the continent, a new summer season peak is also developing. Other than the industrial load, which has traditionally been steady on a daily and seasonal basis, the other major demand sectors (residential, commercial, and electric generation) are weather sensitive and have a high degree of variability. Demand in North America is projected to grow by 19% between 2003 and 2015, whereas industrial demand is projected to grow by only 3%. This would mean that the stable industrial demand sector is becoming a smaller percentage of total demand. This effect is more pronounced in the United States, where industrial demand is projected to decline by 6% from 2005 to 2015.

Demand for power generation, which will make up the majority of projected demand growth, is highly variable on an hourly, daily, and monthly basis. As can be seen in Figures T-23 (historical 1997) and T-24 (projected 2025), power generation not only increases the number and magnitude of winter demand peaks, but it also creates a secondary demand peak in the summer. It also creates an hourly demand profile that is even more pronounced than that of a traditional residential/commercial load profile. The growing summer peak shortens the summer season gas storage injection period, primarily allowing for injections only in the off-peak electric demand hours of the day and



Source: Energy and Environmental Analysis, Inc.

Figure T-23. 1997 Daily Loads for the United States and Canada

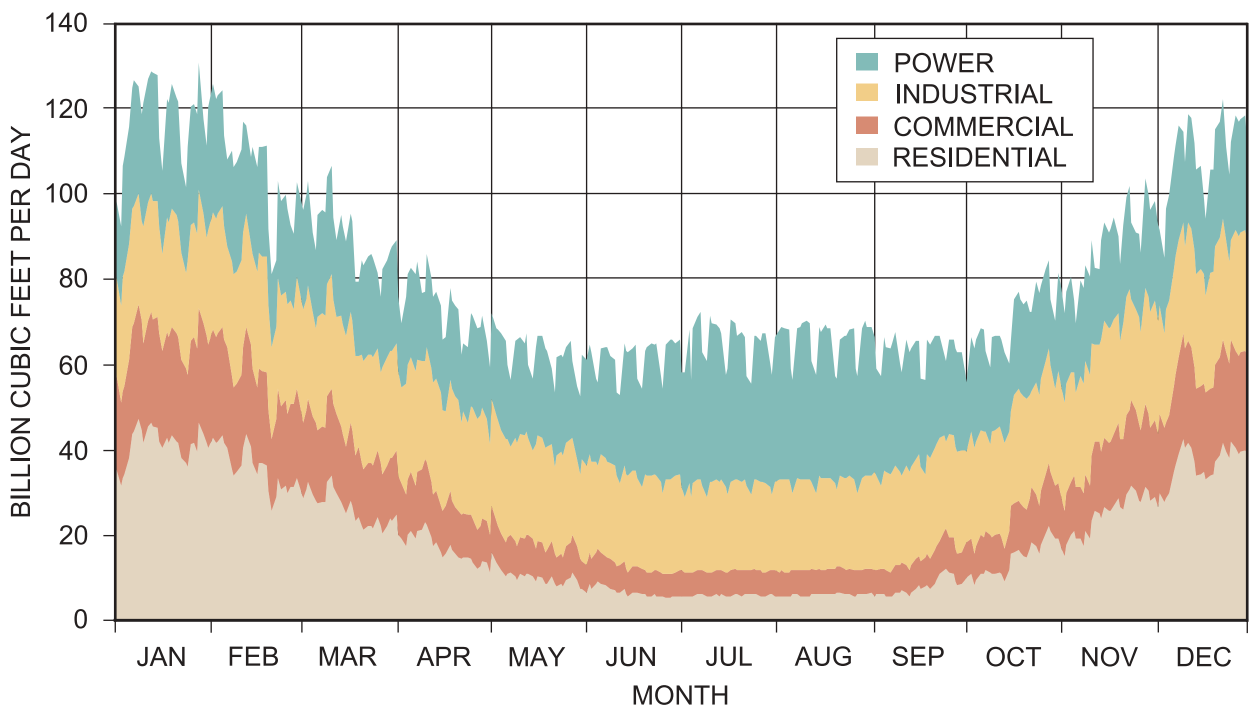


Figure T-24. 2025 Daily Loads for the United States and Canada thus requiring more volume to be injected into the shoulder (historically lower demand) months of April through June and September through October.

The Reactive Path scenario projects the Mid-Atlantic, South Atlantic, and to a lesser extent, the West North Central regions will experience the greatest growth in this summer peak, though in each case, loads during the summer peak remain significantly less than those associated with the winter months. Thus, as gas-fired generation facilities are added to the infrastructure, supply dedicated to serving this market will compete with supply intended for storage injections.

In order to satisfy storage refill requirements, greater injections into storage during the shoulder months of April, May, September, and October will likely be necessary to completely refill storage by the beginning of the winter season. In a supply constrained environment, this "time-compression" of the storage injection season will place upward pressure on summer prices as gas consumed in the power generation sector competes with gas intended for storage.

3. Required/Assumed Infrastructure Additions (Costs)

Projected near-term (2003-2005) demand for seasonal storage could grow by as much as 450 BCF, relative to the requirements of 1999-2002, with most of that increased demand being due to an assumption of a return to more normal weather. As much as 300 BCF of that demand growth may be accommodated by the existing infrastructure. Based on announced projects, it is expected that storage capacity will grow by only 109 BCF by 2005. Additions to working storage capacity in the lower-48 amount to 69 BCF, and consist of projects previously announced to the market. Any remaining incremental near-term demand for storage will need to be met by more efficient utilization of existing capacity and short-term enhancements to the capacity and deliverability of existing facilities. There is a significant risk that any near-term return to more normal weather patterns could not be met by the existing infrastructure without some increase in seasonal gas price variability and volatility. The Pacific region will experience the largest near-term growth at over 29 BCF. The announced projects involving capacity expansion of existing reservoirs at an estimated cost of $1 billion. Over 34 BCF of the near-term storage additions will be high deliverability salt cavern facilities located in the Mid-Atlantic, South Atlantic, West South Central, and Mountain regions, with a total estimated development cost of $211 million.

A mix of new salt cavern storage capacity and depleted reservoir storage projects in the Mountain and East North Central regions make up the remaining 4 BCF in the U.S. lower-48. The total cost associated with these additions is $38 million. Near-term additions to Canadian storage amount to 40 BCF, all of which are located in Western Canada and involve new development in depleted reservoirs. The estimated cost associated with these additions is $100 million.

Projected North American storage infrastructure additions over the 2005-2025 period are approximately 550 BCF, 80 BCF of which will consist of high deliverability salt cavern facilities. In total, future North American storage infrastructure additions over the study period carry an estimated cost of nearly $5 billion.

On a regional basis, the development of 111 BCF of additional depleted reservoir and aquifer storage capacity is projected in the East North Central at an estimated cost of $905 million. Conventional storage additions to the Mid-Atlantic region are forecast at 141 BCF, all of which will likely entail the conversion of depleted reservoirs, at an estimated cost of $1.3 billion.

Growth of conventional storage in the South Atlantic is projected at about 99 BCF, with an estimated development cost of $804 million. The Mountain region is projected to need almost 55 BCF of additional conventional storage with attendant development costs of $468 million.

The remaining additions to the lower-48 storage capacity are projected at almost 87 BCF, at a total estimated cost of $1.07 billion. Projected additions to Canadian storage capacity are 56 BCF, including over 8 BCF of high deliverability storage. All but about 2 BCF of these additions are projected for Eastern Canada. The total estimated cost of storage additions in Canada is $260 million. Table T-11 shows the capacity additions and estimated costs in more detail.

It should be noted that these regional capacity addition estimates are based on model results that may not adequately reflect geological and other factors which favor construction of capacity in some regions relative to others. In particular, it is likely that more of this required capacity will be built in the

Region Number	Region Name	Announced (BCF) 2003-2005	2003-2005 Est. Cost (MM$)	Additions (BCF) 2005-2025	2005-2025 Est. Cost (MM$)
1	New England	-	-	32.1	382
2	Middle Atlantic	5.0	47	108.9	914
3	East North Central	0.9	8	111.4	905
4	West North Central	-	-	36.9	332
5	South Atlantic	7.6	72	98.5	804
6	East South Central	16.0	149	6.0	227
7	West South Central	6.6	62	9.2	282
8	Mountain	3.2	30	54.3	468
9	Pacific	29.3	274	35.1	225
	Total U.S. Lower-48	**68.6**	**642**	**492.4**	**4,539**
10	Canada East	-	-	54.3	250
11	Canada West	40.0	100	1.8	10
	Total Canada	**40.0**	**100**	**56.1**	**260**
	Total North America	**108.6**	**742**	**548.5**	**4,799**

Notes: MM$ = millions of dollars. BCF = billion cubic feet.

Table T-11. Projected Storage Capacity Additions and Costs by Region

major producing regions of the United States and Canada, and less in the market regions than is indicated in the discussion above.

D. Market Needs for Storage

The natural gas storage infrastructure must maintain its ability to serve its traditional markets while developing the capacity to meet new demands on the pipeline system. The traditional markets serve the historical needs of both the gas consuming region markets and the gas producing region markets.

The traditional role of storage in the consuming region has been for seasonal time-shifting of volume from summer availability to winter usage and peak-day deliverability for residential and commercial customers served through regulated LDCs. Seasonal time-shifting of supply refers to the use of storage assets to preposition gas as close to these seasonal end users as possible. Withdrawals of working gas in storage during the heating season augment pipeline supply, which alone would be insufficient to meet the increased wintertime demand. The critical nature of this role was reinforced by the experience of the 2002-2003 heating season – one with widespread and persistently frigid temperatures that caused the industry to withdraw working gas down to record low levels. Related to seasonal shifting, a key role for storage is to meet peak-day demand requirements. On the highest demand days, storage provides the bulk of gas sendout for at least some LDCs.

The traditional role of storage in the producing region has been for seasonal time-shifting by producers of gas. This role has been increasingly filled by gas marketers who, hoping to capture price advantage, use the storage capacity to buy during periods of oversupply while selling in periods of undersupply.

Over the past several years, as electric generators have installed more and more gas-fired generation assets, a secondary peak is developing in the summer months related to space cooling requirements. This new source of demand is altering the traditional seasonal demand for gas and increasing the daily demand for gas deliverability. Figure T-25 illustrates the large surge in demand during the heating seasons, and the developing secondary summer surge in demand. Although not as pronounced as the winter peaks, the secondary peaks occur during the refill season and compete for supplies that otherwise might be available for storage injection. The increased use of natural gas for electric generation is increasing the load management challenge for pipelines and storage operators on a daily and even intra-day basis.

Therefore, the operation and utilization of storage is evolving, and the industry faces the growing challenge of refilling inventory for traditional heating season requirements in competition with a growing summer demand surge while also managing the ever more frequent fluctuations in demand load.

E. The Outlook for Storage

Market dynamics have created a growing need for multiple cycle storage facilities. In recent years there have been several occasions when winter/summer seasonal price spreads have declined to such low levels that seasonal storage of gas for price arbitrage purposes has been uneconomic. However, the operational need to store gas to balance winter and summer demand with relatively flat gas supplies has remained. In addition, the gas market's fluctuation on a day-to-day, week-to-week and month-to-month basis demands quick turnaround of storage inventories. With credit concerns, i.e., cash flow, becoming an issue for many gas traders and marketers, storing gas without access to it for 6-8 months can be a risky proposition.

Electric generation demand in summer will compete with storage injection requirements during the summer cooling season. This issue has been in place for a number of years. Most multiple cycle storage operators are familiar with the double dipping of inventories due to cooling load in the summer and heating load in the winter. This is the effect of summer season generation demand on the pipeline infrastructure, and this effect continues to strengthen. If the pipeline infrastructure is strained due to peak summer loads, scheduled storage refills can be interrupted. As this phenomenon increases, there will be more and more of these refill interruptions. For those storage facilities with rigid refill requirements, this can become a serious problem. Less rigid requirements will have to be considered, which might require more horsepower

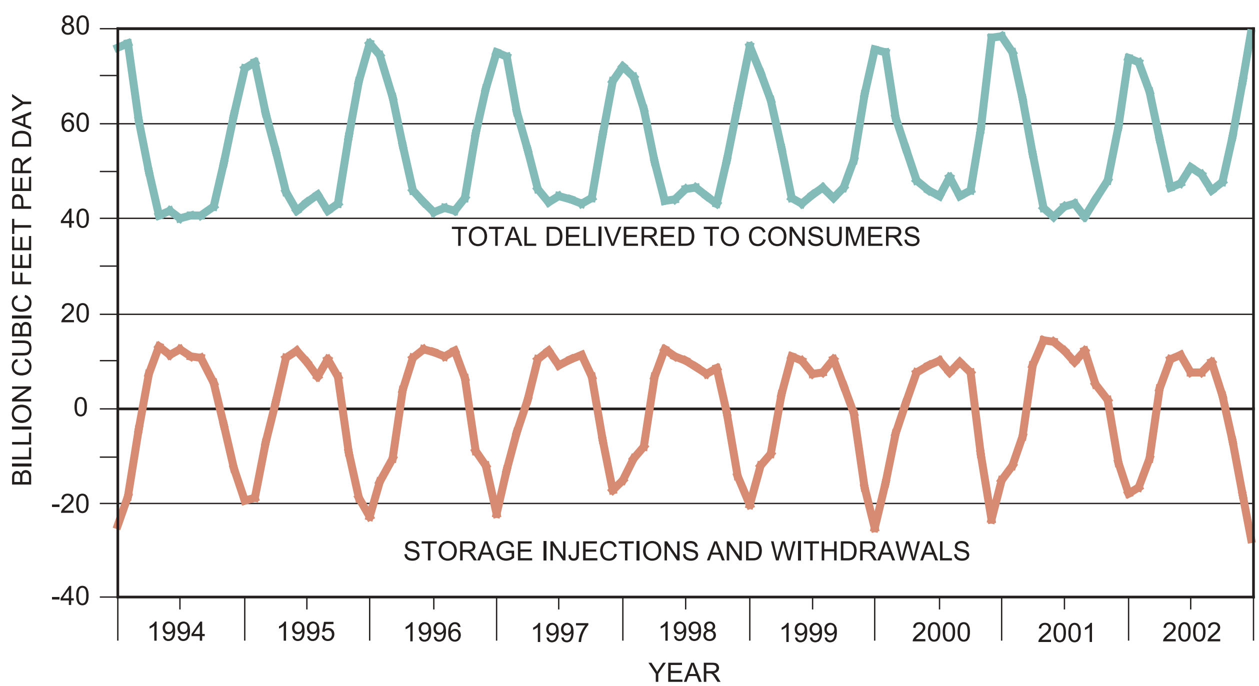


Figure T-25. Deliveries to Consumers and Storage Injections/Withdrawals, 1994 to 2002 installation, more wells, or reductions in the level of working gas available from year-to-year.

F. Challenges to Building and Maintaining the Required Storage Infrastructure

1. Access Limitations

The difficulty of siting storage facilities can be attributed to the need to find a site with the appropriate combination of geological features, pipeline proximity, and the ability to obtain land, rights, and permitting. Once a geologically suitable site is found at an acceptable location with respect to the natural gas pipeline infrastructure, the ability to obtain permitting, land, and development rights becomes critical. The primary access limitations on developing storage capacity are the difficulties in dealing with multiple governmental entities, limitations on emissions, and limitations on storage reservoir operating pressures.

The inconsistency in requirements for FERC and state facility certifications increases the time and cost to develop storage facilities. Proving necessity, i.e., market need, and tailoring implementation plans for minimization of environmental impact are two areas that can have widely varying meanings depending on the approval entity involved. When two or more entities must be satisfied, the complexity involved in satisfying all parties increases exponentially.

It is estimated that existing storage facilities can be expanded to increase capacity by as much as 5%. However, modification of an existing storage field can prove to be as difficult, if not more difficult, than new development. Two examples of this are regulations that limit emissions and regulations that limit the maximum pressure in a storage reservoir.

Limitations on air emissions effectively restrict the amount of compression that can be used to support injection and/or withdrawal activities in a storage facility. Since the ability to inject gas into a reservoir is dependent on the facility's compression capacity, injection capacity is a common limiting factor on the effective capacity, or the ability to cycle a storage field. As a result, many storage operators in emissions-controlled regions limit injection rates to 50% of withdrawal rates. This is particularly evident in the Rockies, California, and the Northeast regions. Operating existing fields more efficiently is often more cost-effective and environmentally sound than new facility development.

In a similar manner, the ability to increase the operating pressure in a storage reservoir can improve the efficiency of existing assets. States generally limit the maximum pressure in a reservoir to the discovery pressure of the reservoir. The ability to safely delta pressure (increase) a reservoir can substantially and cost-efficiently expand the capacity and deliverability of the existing reservoir.

2. Limited Nature of Suitable Geologic Sites

Any access restrictions can have an even greater impact when the limited number of sites is considered. Depleted reservoirs, aquifers suitable for storage, and salt formations are all of limited extent in North America. Any target storage formation must first be reasonably close to a major pipeline before practical storage development can be considered. This initial and obvious requirement limits many suitable geologic formations from consideration for storage development. Very few states have suitable depleted reservoirs, aquifers, and salt formations available for practical storage development. The mere presence of a candidate geologic formation for storage cavern development may not be sufficient to warrant practical storage development. For example, even though there are extensive bedded salt deposits in the Northeast United States, storage cavern development has been difficult to justify economically in the Northeast because there are few options for disposing (or otherwise utilizing) the massive salt brine volumes that naturally result from salt cavern development.

3. Costs to Create Storage Infrastructure

Deregulation of the interstate pipelines under FERC Order 636 has had a significant impact on the availability of cost data associated with new storage projects. Prior to Order 636, new storage developments and expansions to existing interstate storage facilities were typically approved by the FERC under traditional cost of service rate treatment. Costs associated with new storage and storage expansions were contained in the Exhibit K portion of an organization's application to FERC. As such, storage development cost data were considered in the public domain and were readily available for review and analysis.

Order 636 afforded some storage operators and developers alike with the option to seek authority to develop new storage facilities under the concept of market-based rates wherein the applicant is not required to submit development cost data. This option is open to developers who can demonstrate the absence of what is referred to as market power, i.e. that competitive alternatives either exist within the nearby market or could be developed by someone else under a similar rate structure.

The assumptions used in this study concerning costs associated with expanding existing storage facilities and development of new facilities were based upon a review of FERC filings dating back to 1994. The review revealed that costs associated with expanding existing depleted reservoir and aquifer storage facilities do remain available in FERC documents since most expansions over the past 8 years have been performed under existing rate structures (cost-of-service rate structure). Most new storage developments on the other hand have been filed under the market-based-rates option, and thus, review of development cost data for these facilities is very limited.

No single source of cost data for expansion of intrastate storage facilities exists; thus, expansion costs for intrastate facilities are not reflected herein, though costs should conform to those of similar interstate expansions. A total of seven applications were listed on the FERC website, six of which included cost data. These applications were reviewed and the cost data contained in them used to establish average costs associated with enhancing existing storage facilities. Data and cost information for one Canadian project was supplied by the operator and is included here for purposes of establishing development cost data. Table T-12 lists all of the projects and summarizes the additional facilities, increase in storage capacity, and/or deliverability for which FERC or comparable regulatory approval was sought.

These data indicate expansion costs ranged from a low of $0.17 million per BCF to a high of $9.10 million per BCF over an eight-year period, with the average cost being approximately $2.5 million per BCF of incremental capacity. For purposes of this exercise, we've assumed this average cost is reasonable and typical of the costs associated with expansions to both inter- and intrastate storage facilities.

Costs associated with expansions of salt cavern storage facilities were not available on the FERC website.

Docket No.	Filed Date	Company	Field Name	State	Capacity Increase (BCF)	Total Project Cost ($MM)	Enhanced Storage Cost ($MM/BCF)
Depleted Reservoirs							
CP02-409-000	7/17/2002	ANR Storage	Excelsior 6	MI	4.0	4.4	1.10
CP01-67-000	1/17/2001	SouthWest Gas Co.	Howell	MI	1.3	3.9	3.12
CP98-546-000	5/13/1998	Columbia	Ripley	WV	0.8	7.3	9.10
CP98-637-000	6/26/1998	Columbia	Glady	WV	0.7	0.1	0.17
CP96-213-000	2/28/1996	Columbia	Various	Various	16.8	53.3	3.17
CP95-62-000	11/4/1994	Columbia	Crawford	OH	8.2	8.4	1.03
CP02-391-000	6/24/2002	Natural Gas Pipeline	North Lansing	TX	10.7	31.1	2.90
	10/1/2002	Intragaz	St. Flavian	Quebec	2.9	3.2	1.10
				Total	45.4	111.7	
					Average Cost		**2.46**

Notes: MM$ = millions of dollars. BCF = billion cubic feet.

Table T-12. Summary of Storage Expansion Costs – Regulated Facilities

Estimates based on industry experience range from approximately $2-3 million per BCF, depending on where in the country the expansion occurs.

For those few projects that have been developed under intra-state authority, there is no central repository for cost data and access to such data at the state level is limited. For purposes of this exercise, we have assumed an average cost for development of new depleted reservoir and aquifer storage of $2 million per BCF of working gas capacity based on industry experience.

4. Impacts of Price and Basis Risk on Infrastructure Development

Historically, a principal function of the North American gas storage infrastructure has been that of balancing highly seasonal and weather-sensitive fluctuations in demand, with relatively flat year-round supply. The principal alternatives to storage generally rely on significant gas price variability and volatility to force a supply/demand balance: during times of excess supply, i.e., the gas price must fall low enough to induce producers to shut in gas production, and/or during times of excess demand the price must rise high enough to force short-term demand destruction.

In an environment in which gas supply remains increasingly challenged to keep pace with growing demands for natural gas, it is to be expected that producers will have an incentive to maintain gas production at near maximum capability at all times, as has generally been the case in recent years. The principal alternative to the short-term balancing role of gas storage in the future, then, is likely to be some form of forced demand destruction, through the price mechanism or otherwise. The adequacy of storage capacity, then, is increasingly important to supporting a market that can continue to grow while providing reasonable assurances of supply and acceptable levels of gas price volatility.

The seasonal balancing requirements of the North American gas market are expected to grow at a rate approximately equal to the overall rate of growth in total gas consumption. This total balancing requirement (defined as the total amount of gas that would need to be injected into storage during the April to October injection season and withdrawn during the November to March withdrawal season to allow average daily gas production to remain constant) has averaged approximately 2.3 TCF during the period 1999-2002, a level consistent with actual annual storage injections and withdrawals during that period, a period of generally warmer than normal winters on average.

A return to "normal" weather, combined with continued gas market growth, would see this annual balancing requirement grow by 15% to 20% by 2005, to approximately 2.7 TCF. Beyond 2005, the balancing requirement is expected to grow consistent with overall demand growth such that total balancing requirements fluctuate around 10% of total annual demand.

The continued strong growth in demand for seasonal balancing is primarily a function of projections of very strong growth in gas demand for power generation. This includes requirements of electrical consumers, which is sensitive to both actual summer and winter weather, as well as the traditional winter residential and commercial heating demand. Industrial demand, on the other hand, which tends to be more evenly distributed throughout the seasons, will show little total growth. The overall effect of these trends will be relatively higher future growth/needs in the winter months than in overall annual demand. Due to this incremental growth in gas-fired power generation, there is also a continuation of recent trends towards a secondary summer peak in demand, albeit modest in comparison to the continuing growth in the winter peak.

Despite the fact that, on average, the past four years have experienced relatively moderate seasonal balancing requirements due to somewhat warmer than normal winters, seasonal gas price variability and volatility have been significant. An objective of avoiding even greater price variability and volatility in the future would suggest that storage working gas capacity may need to grow by as much as an additional 250 BCF between 2005 and 2015, and an additional 300 BCF between 2015 and 2025. Gas storage capacity growth to meet these targets will require an adequate resource base of further storage development opportunities and market incentives that encourage investment in expansion of existing facilities and development of new facilities.

5. Market Signals and Financial Requirements

The capital investments that would be required to add 700 BCF of additional working gas capacity by 2015 are significant, yet small relative to the potential capital requirements in other sectors of the natural gas industry. A more significant issue with regard to financing storage capacity growth is whether there will be adequate market signals to encourage such investment.

Storage development costs vary significantly from region to region and by facility type. Expansions of existing facilities have the potential to add approximately 200 BCF of incremental capacity at an average cost in the range of $5 million per BCF of working gas, while new projects will require $5 million to $10 million per BCF. Total financial requirements of adding 700 BCF of working gas capacity by 2025 are likely to be in the range of $4 to $6 billion.

Similar to pipeline transmission capacity, contracting practices for natural gas storage capacity are currently undergoing significant change, and it is not yet apparent how the market requirement for increased capacity will be translated into contractual arrangements to underpin investments. Generally speaking, storage customers can be classified into two broad categories: those who contract for capacity for its value in capturing time period gas price arbitrage margins (summer/winter price differentials; spot versus future month differentials etc.) and those who contract for capacity to meet their operational and reliability requirements without regard to price arbitrage opportunities. Traditionally, LDCs have held a large proportion of total storage capacity and have tended to operate with relatively price-insensitive storage injection and withdrawal targets, using storage capacity as a vital asset in satisfying their obligation to meet winter peak demands. Until recently, the fastest growing segment of storage customers was the energy marketing companies who were primarily focused on price arbitrage opportunities. Over the last 18 months, however, there has been a noticeable retreat from gas storage contracting by energy marketing companies, due in no small part to the financial difficulties of this segment. Thus the entities that will contract for the necessary storage facilities to meet future growth needs remain uncertain.

Also, market and regulatory trends of recent years have caused LDCs to become less active in contracting for long-term gas storage capacity. The introduction of customer choice programs and the uncertainties regarding the LDC's role as "supplier of last resort" (as discussed in the Distribution section of this report) have presented difficulties for LDCs in forecasting their future contractual requirements for gas supply, pipeline capacity, and storage capacity. At the same time, in the recent past there was a strong movement towards LDC reliance on energy marketing companies to manage their contracted LDC storage capacity, often through short-term asset optimization arrangements between LDCs and marketers.

Coupled with market conditions that were characterized by relatively small summer/winter spreads throughout the first five months of 2003, these trends have resulted in what is currently described by storage developers as a "very soft market" for the development of new gas storage capacity, notwithstanding the positive longer-term fundamentals as echoed herein.

In order for gas storage capacity development to meet anticipated future demands, storage developers feel they must see a revitalization of demand for multi-year gas storage contracts through some combination of customers such as LDCs and others with firm obligations to serve seasonal and peak-day market requirements for critical needs customers, and/or the emergence of a business sector which is capable of performing this role while also in pursuit of price arbitrage opportunities.

6. Development Lag

There is an extensive delay between project initiation and completion. Although development time lags vary significantly by region and by type of storage, on average it is expected that there will be a lag of 3 years or more between project identification and completion. Assuming favorable market conditions, as discussed in the previous section, this development lag should not pose a significant problem for the 550 BCF of capacity that would need to be added between 2005 and 2025. However, it does mean that any portion of the potential increase of 400 BCF in demand for storage prior to 2005 that can not be met by increased utilization and enhancements of existing facilities, is almost certainly going to result in increased gas price variability and volatility during that period. As previously discussed, this potential near-term increase in demand for storage will be very dependent on weather, and is based on an assumption of a return to more normal weather patterns, relative to recent years of warmer than normal winters.

7. Technological Impacts

New technologies for gas storage performance are continually being investigated by the industry and industry support agencies. For example, the Gas Technology Institute (GTI), the United States Department of Energy (USDOE) National Energy Technology Laboratory (NETL), and the Solution Mining Research Institute (SMRI) all fund ongoing research and development activities in gas storage performance improvements. Many specific examples of gas storage performance improvement are noted on the cited agency websites. Two examples of gas storage improvements and research are briefly described below. Many others are being pursued through active research efforts.

a. Horizontal Injection/Withdrawal Wells

Horizontal gas storage wells have the potential to significantly improve the injection and withdrawal performance and the efficiency of existing and newly developed gas storage reservoirs. Based on the results of a 1991 study funded by the Gas Research Institute,[23] in excess of 70% of the storage capacity in the United States and Canada is associated with reservoirs that are considered good to excellent candidates for horizontal wells based on their petrophysical characteristics. Properly applied, this technology can enhance gas deliverability, recovery of working gas from poorly-drained regions of a reservoir, increase the amount of gas available to cycle by reducing reservoir working pressure, and reduce environmental impact.

While there are a number of considerations that come into play in determining whether horizontal wells may enhance storage reservoir performance, some rules of thumb may be applied. Generally speaking, the technology is best suited for relatively thin, homogeneous reservoirs, and reservoirs which exhibit natural fracturing. Horizontal wells tend to be more effective in thinner formations because the incremental increase in wellbore-reservoir contact area is much larger than for relatively thick formations.

Vertical and horizontal permeability, which are measures of the ease with which gas flows through porous rock, are extremely important as well. Vertical permeability is a key parameter in horizontal wells in that it controls gas flows in the reservoir from above and below the wellbore. In particular, the ratio of horizontal to vertical permeability has a dramatic impact on horizontal well deliverability. All else being equal, a horizontal to vertical permeability ratio less than 1.0 indicates reservoir properties may be ideal for horizontal gas storage well applications.

In low and high permeability gas storage reservoirs alike, horizontal wells can significantly improve deliverability and drainage. In low permeability reservoirs (< 1 millidarcy), it may be difficult for a single vertical well to efficiently drain a large area. For example, in storage reservoirs with permeability ranging from 0.1 – 0.01 millidarcies, a single vertical well located on 40 acre spacing would not be capable of efficiently draining that area within the timeframe of a typical storage withdrawal cycle (120-150 days); several vertical wells would be necessary.

Conversely, a properly completed horizontal well could adequately drain a 40-acre tract. In high permeability reservoirs, vertically completed wells experience near-wellbore turbulence due to increasing flow velocity as gas flow converges on the near-wellbore area. This near-wellbore turbulence is inversely proportional to the length of the interval open to the storage formation and results in additional pressure loss that impacts deliverability. Horizontal wells are much less prone to this effect because a significantly larger interval is typically open to the storage formation.

Deployment of horizontal well technology in the gas storage industry has increased steadily since the early 1990s. While there is no known repository for industry statistics, a random survey of a number of major storage operators suggests that application of this technology is well developed. Discussions with a number of operators indicate that horizontal gas storage well deliverability often ranges from 6-10 times that of conventional vertical wells in the same reservoirs. A few operators reported that they have successfully implemented horizontal well in-fill drilling programs to convert base gas to working gas, thereby increasing the percentage of total inventory which can be cycled; increases in cyclable capacity ranged from approximately 8-15%.

Several operators also reported that horizontal wells have provided access to previously under-drained regions of storage reservoirs because surface access restrictions prohibited the drilling of conventional vertical wells (in one instance, the under-drained region was beneath a major wetland where conventional surface access was not possible). One operator reported a

[23] Gas Research Institute, *Critical Performance Parameters for Horizontal Well Applications in Gas Storage Reservoirs,* June 1993.

significant reduction in horsepower utilization and fuel savings as a result of plugging many older vertical wells and replacing them with branched horizontal wells. Even though costs for horizontal wells were reported to range from 2-3 times the cost of conventional vertical wells, the economics still favored horizontal well deployment.

As the existing storage infrastructure ages and replacement of wells becomes a necessity, it is highly likely that storage operators will turn increasingly to horizontal wells to maintain or improve deliverability, working gas capacity, and efficiency. Horizontal drilling technology lends itself well to locating several storage wells on a single pad at the surface. This type of design affords the added benefit of simplifying and significantly reducing the extent of gathering system piping.

b. Lined Rock Cavern Storage

As noted previously, high deliverability storage (possible with salt caverns for example) cannot be developed in many areas of the United States with practical capital expenditures. The Northeast and many parts of the Southeast are not suitable for conventional salt cavern development. Another option for high deliverability storage in these regions is Lined Rock Cavern (LRC) storage. The LRC technology is being pursued in Sweden where a pilot scale facility soon will be in operation. Application of the LRC technology initiates with the excavation of a shallow cavern in a "hard rock" formation. A "lining" of concrete and a very thin steel shell is then installed that allows the cavern to sustain very high gas pressures. The gas pressures in the LRC facility can be far in excess of the gas pressures that would be possible in an unlined cavern, but still must be below the pressure that would "lift" the overlying rock formation or otherwise cause enough rock formation movement to damage the thin steel lining.

The LRC technology has been reviewed by Department of Energy's National Energy Technology Laboratory and was found to be economically impractical in the U.S. Northeast primarily because of the high labor cost associated with excavation and tunneling in the United States. It is nonetheless possible that this technology might eventually be modified so as to be financially attractive in areas of the United States in which other types of high deliverability storage cannot be developed.

VI. Comparison to Other Transportation Outlooks

An assessment of recent pipeline projects indicates that North American inter-regional pipeline capacity grew by 11.4 BCF/D from 1999 to 2002. This capacity growth exceeded the prediction of 8.7 BCF/D made in the 1999 NPC study. Most of the difference occurred in the Southeast and the Rocky Mountains. The growth in the Southeast was related to greater than expected market expansion (market pull), while the Rocky Mountain growth was in response to increased supply deliverability (supply push). The estimated average annual cost of these expansions was approximately $6.1 billion.[24] This compares to a 1990s average expenditure for the United States and Canada of $2.5 billion.[25]

The cost of pipeline construction per mile in the early to mid-1990s increased at an annual rate of 1.5% per year. Costs grew more rapidly from 1998 to 2000, averaging over 11% per year. Costs declined somewhat after the construction peak in 2000 because a smaller number of active projects led to lower prices for pipe, materials, and construction crews. However, despite the recent decline in construction activity, the growth rate in cost per mile increased by 3.1% per year from 1993 through 2002, which is twice the rate projected in the 1999 NPC Study. The primary factors leading to larger than projected cost increases were higher expenses for right-of-way and labor.

Peak construction years for transmission pipelines in this study occur when Arctic pipelines are under construction (2008-2013). The overall construction estimates are lower than those that were projected in the 1999 NPC study, principally because of:

- Lower natural gas demand
- Lower production estimates from mature production regions
- Significantly higher imports of liquefied natural gas (LNG) directly into East and West Coast markets
- Utilization of existing pipeline infrastructure to transport gas from growing production regions.

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24 The INGAA Foundation, Inc., *Pipeline and Storage Infrastructure for a 30 Tcf Market – An Updated Assessment*, 2002.

25 Ibid.

VII. Transmission, Distribution, and Storage Recommendations

Sustain and Enhance Natural Gas Infrastructure

Although the United States and Canada have an extensive pipeline, storage, and distribution network, additional infrastructure and increased maintenance will be required to meet the future needs of the natural gas market. The recommended actions listed below are required to ensure efficient pipeline, storage, and distribution systems:

- **Federal and state regulators should provide regulatory certainty by maintaining a consistent cost recovery and contracting environment wherein the roles and rules are clearly identified and not changing.** Regulators must recognize that aging infrastructure will need to be continuously maintained and upgraded to meet increasing throughput demand over the study period. They must also recognize that large investments will be required for the constructions of new infrastructure. To make the kinds of investments that will be required, operators and customers need a stable investment climate and distinguishable risk/reward opportunities. Changes to underlying regulatory policy, after long-term investments are made, increase regulatory and investment risk for both the investor and customers.

- **Complete permit reviews of major infrastructure projects within a one-year period utilizing a "Joint Agency Review Process." Projects that connect incremental supply and eliminate market imbalances should be the highest priority and expedited.** Where available supply is constrained, FERC should expedite timely infrastructure project approvals that will help mitigate the current supply demand imbalance. Longer term, new project reviews should be expedited via continuing enhancement and increased participation in a Joint Agency Review Process, similar to that which FERC has utilized recently. A Joint Agency Review Process would require up-front involvement by all interested/concerned parties including appropriate jurisdictional agencies allowing the decision process to proceed to approval and implementation more accurately, more timely, and at lower overall cost. The final FERC record should resolve all conflicts. The areas of greatest concern in this regard are requirements of the U.S. Army Corps of Engineers, Coastal Zone Management Act, and Section 401 of the Clean Water Act, all of which could hinder the orderly implementation of FERC certificates. This process must also assure that a project, which has used and successfully exited this process, may proceed per the direction received and will not be delayed by non-participating parties or other external regulatory standards or processes. This suggestion is a more-specific rendering of the 1999 NPC study's fifth recommendation: "Streamline processes that impact gas development." The NPC supports legislation that accomplishes the "Joint Agency Review Process" as described above. Regulators at federal, state, and local levels, with cooperation of all participating parties, should establish processes and timelines that would complete the regulatory review and approval process within 12 months of filing.

- **Regulatory policies should address the barriers to long-term, firm contracts for entities providing service to human needs customers.** Many LDCs will not enter into long-term contracts in today's market out of fear that regulators may subsequently deem them imprudent in the future. Similarly, power producers, especially those that provide peaking service, are reluctant to contract for firm pipeline service because charges for firm service cannot be economically justified in power sales. As discussed in Finding 9 in the Summary volume of this report, this practice is impairing the investment in infrastructure. The result is that regulatory practices that limit long-term contracts (prudence reviews and ratemaking) inhibit efficient markets and discourage the development and enhancement of pipeline infrastructure. The regulatory process must allow markets to transmit the correct price signals and enable market participants to respond appropriately. Regulators should encourage, at all levels of regulation, policies that endorse the principles of reliability and availability of the natural gas commodity. All regulatory bodies should recognize the importance of long-term, firm capacity contracts for entities providing service to human needs customers and remove impediments for parties to enter into such contracts.

- **FERC should allow operators to configure transportation and storage infrastructure and related tariff services to meet changing market demand profiles.** At the interstate level, FERC should continue to allow and expand flexibility in tariff rate and service offerings and continue to allow market-based rates for storage service where markets are shown to be competitive so that all parties can more accurately value services and make prudent contracting decisions. To ensure that existing and future transmission, distribution, and storage facilities can be adapted to meet the significantly varying load profiles of increased gas-fired generation, FERC and state regulators need to allow and encourage operators to optimize existing and proposed pipeline and storage facilities. In some cases, this will require a significantly more flexible facilities design based upon peak hourly flow requirements, and/or a modification to existing facilities to provide for optimizing storage injections in off-peak hours or in shoulder months.

- **Regulators should encourage collaborative research into more efficient and less expensive infrastructure options.** Funding for collaborative industry research and development is in the process of switching from a national tariff surcharge-funded basis to voluntary funding. Because of the benefits of reduced costs, system reliability, integrity, safety, and performance, DOE should continue funding for collaborative research. Regulators need to encourage and remove impediments regarding cost recovery of prudently incurred R&D by the operators to fund necessary collaborative research.

APPENDICES

The Secretary of Energy
Washington, DC 20585

March 13, 2002

Mr. William A. Wise
Chairman
National Petroleum Council
1625 K Street, NW
Washington, DC 20006

Dear Chairman Wise:

In the last decade, the National Petroleum Council conducted two landmark studies on natural gas, the 1992 study ***Potential of Natural Gas in the United States*** and the 1999 study ***Meeting the Challenges of the Nation's Growing Natural Gas Demand***. These studies provided valuable insights on the potential contribution of natural gas to the Nation's economic, energy and environmental future, and the capabilities of industry to meet future natural gas demand and changing market conditions.

Considerable change has occurred in natural gas markets since the Council's 1999 study, among these being new concerns over national security, a changed near-term outlook for the economy, and turbulence in energy markets based on perceived risk, price volatility, fuel switching capabilities, and the availability of other fuels. The Nation's reliance on natural gas continues to grow, with U.S. consumption projected to increase by 50 percent in the next 20 years. However, the availability of investment capital and infrastructure, the pace of technology progress, access to the Nation's resource base, and new sources of supplies from Alaska, Canada, liquefied natural gas imports, and unconventional resources such as methane hydrates are factors that could affect the future availability of natural gas supplies.

Accordingly, I request that the Council conduct a new study on natural gas in the United States in the 21st Century. Such a study should examine the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It should also provide insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. Of particular interest is the Council's advice on actions that can be taken by industry and Government to increase the productivity and efficiency of North American natural gas markets and to ensure adequate and reliable supplies of energy for consumers.

I am designating Mr. Robert G. Card, Under Secretary for Energy, Environment and Science, and Mr. Carl Michael Smith, Assistant Secretary for Fossil Energy, to represent me in the conduct of this important study. I offer my gratitude to the Council for its efforts to assist the Department in defining the scope of the study request and I recognize that refinements may be necessary after the study starts to ensure that the most critical issues affecting future natural gas demand, supplies, and delivery are addressed.

Sincerely,

Secretary Abraham

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 (NPC) 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. The Council reserves the right to decide whether it will consider any matter referred to it.

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

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APPENDIX C

INDIVIDUAL COUNTRY SUMMARIES
PREPARED BY WOOD MACKENZIE

1.0. Pacific Basin Supply Projects

Project: North West Shelf Expansion (Australia)

Field Status:	Under Development
Location:	Barrow Sub-basin/ Western Australia

Participants

Woodside:	16.67%
BP:	16.67%
BHP:	16.67%
Shell:	16.67%
Mitsubishi & Mutsui:	16.67%
ChevronTexaco:	16.67%

Project Reserves

Gas (tcf):	9.2
Liquids (m.bbl):	Condensate 310, LPG 100

Estimated FOB Resource Cost: $1.00-1.50/mcf

Supply

The North West Shelf Gas Project encompasses a total of 11 fields, of which North Rankin, Goodwyn, Perseus and Echo/Yodel are the most significant. The expansion of the project, involving the building of two additional trains, namely Trains 4 and 5, will utilise feedstock primarily from Perseus and Echo/Yodel fields. The fields are currently being developed, through a platform centred on the Perseus field, feeding a new gas pipeline to the liquefaction plant.

The upstream economics of the project are enhanced by virtue of the high liquids content of the fields and the ability to utilise some existing infrastructure currently supplying Trains 1-3.

Project: Gorgon Area (Australia)

Field Status:	Technical Reserves
Location:	Barrow Sub-basin/ Western Australia

Participants

ChevronTexaco:	57.14%
ExxonMobil:	14.29%
Shell:	28.57%

Project Reserves

Gas (tcf):	5.5
Liquids (m.bbl):	96

Estimated FOB Resource Cost: $2.00-2.50/mcf

Supply

The Gorgon Area currently encompasses five gas/condensate fields located along the Rankin platform with a huge combined recoverable reserve base. This already considerable reserve base has been added to with the recent announcement of the 20 tcf+ ExxonMobil operated Jantz discovery, located to the northwest of the existing Gorgon complex.

The current development scenario envisages a subsea development, via 5 production centres, employing 6 wells each. The hydrocarbons will then be piped 70 kms to Barrow Island via dual 26" flow lines where processing will occur, the CO_2 removed and re-injected into deep reservoirs on the island. It is hoped that this sub-sea development plan will markedly improve the feedstock economics when compared to a conventional platform based development.

Project: Greater Sunrise Area (Australia)

Field Status:	Technical Reserve
Location:	Timor Sea/ Northern Territory

Participants

Osaka Gas:	10.00%
ConocoPhillips:	30.00%
Shell:	26.56%
Woodside:	33.44%

Project Reserves

Gas (tcf):	5.25
Liquids (m.bbl):	187

Estimated FOB Resource Cost: $2.00-2.50/mcf

Supply

The Greater Sunrise Area is made up of the Sunrise, Loxton Shoals, Troubadour and Sunset fields and is situated in the Bonaparte Basin in the Timor Sea. It is located approximately 500 km north of the city of Darwin and around 200 km North East of the Bayu-Undan field in the East Timor-Australia JPDA. The fields were first discovered in 1974 and various participants have been trying to monetise this large stranded gas resource ever since.

In November 2000 interest in the area was renewed with the signing of a co-operative agreement between Woodside and Shell and Phillips Petroleum, operator of the Bayu-Undan venture. However the co-operative agreement has since stumbled from one crisis after another. In 2001, Shell proposed the concept of he world's first floating LNG facility (FLNG) to be located over Greater Sunrise. ConocoPhilips, however stated its preference for piping the gas ashore to supply the Australian domestic market. Subsequently a review of the domestic market was undertaken in 2H 2002. The review revealed the demand from the domestic market was insufficient to meet the supply from the Greater Sunrise Area and so this development scenario was scrapped. The JV now appear focussed on the FLNG scenario and are currently targeting markets in Asia. The field however, is unlikely to come onstream before 2010.

Project: Bayu-Undan (East Timor – Australia JPDA)

Field Status:	Under Development
Location:	Timor Sea, Zone of Co-operation/Area A

Participants

ConocoPhillips:	56.27%
Santos:	11.83%
INPEX:	11.70%
Petroz:	8.25%
Agip:	12.32%

Project Reserves

Gas (tcf):	3.8
Liquids (m.bbl):	220

Estimated FOB Resource Cost: $2.00-2.50/mcf

Supply

Bayu Undan is a single, large gas/condensate field which straddles the blocks JPDA 91-13 and JPDA 91-12 in the East Timor-Australia JPDA in the Timor Sea. The field was discovered in 1995 and various participants have been trying to commercialise it since then. The current planned development is in two phases: (i) a liquids stripping/gas recycling project, and (ii) a gas export project. Development of the liquids stripping/gas recycling project is currently underway with first production expected in early 2004. The field will be exploited via 3 fixed platforms and an attendant FSO vessel. Gas volumes will be re-injected until 2006, when commercial gas production is expected to commence.

The upstream feedstock economics are attractive by virtue of the very rich liquids content of the gas.

Project: Bontang Train I (Offshore Mahakam) (Indonesia)

Field Status:	Onstream, Probable and Tech Res
Location:	East Kalimantan, Indonesia

Participants

TotalFinaElf:	50.00%
INPEX:	50.00%

Project Reserves

Gas (tcf):	3.8
Liquids (m.bbl):	55

Estimated FOB Resource Cost: $1.00-1.50/mcf

Supply

The Offshore Mahakam PSC is the largest gas supplier to the non profit making Bontang LNG plant. Of the latest package of LNG contracted from the plant, signed in 2000, the Offshore Mahakam PSC is contracted to supply over 82%. The PSC has 13.2 tcf of 2P uncontracted wet gas with significant upside potential and represents the most likely supplier for future tranches of gas to the Bontang plant. The resource cost estimate assumes the Tunu and Peciko would initially supply the Train I feedstock, with the later development of the Nubi and Sisi fields supplementing production. Although, the reservoirs are complex, the large fields provide significant economies of scale and, combined with the shallow water, the proximity to shore and the extensive existing infrastructure the fields can be developed at very low cost.

Project: Tangguh (Vorwata, Wiriagar, Ubadari) (Indonesia)

Field Status:	Probable Development
Location:	Irian Jaya, Indonesia

Participants

BP:	37.1%
CNOOC:	12.5%
Nippon Oil Corp.:	12.2%
BG:	10.8%
Kanematsu:	10.0%
Mitsubishi Corp:	9.1%
INPEX:	7.2%
Nissho Iwai:	1.1%

Based upon proven reserves

Project Reserves

Gas (tcf):	7.7
Liquids (m.bbl):	35

Estimated FOB Resource Cost: $1.50-2.00/mcf

Supply

It is proposed that the fields Vorwata, Wiriagar, Ubadari and others on the Muturi, Berau and Wiriagar PSCs will provide the feedstock for the greenfield Tangguh LNG development. The proposed development scenario envisages a single processing platform, 30-40m kms offshore, processing production from 2 well head platforms on Vorwata and a single well head platform on Wiriagar.

The attractive economics of the upstream feedstock are largely due to the excellent well productivity and shallow water, close to shore location of the fields.

Project: MLNG Tiga (Jintan, Serai, Helang, Layang) (Malaysia)

Field Status:	Under Development
Location:	Sarawak, Malaysia

Participants

SK8

Shell:	37.50%
Nippon Mitsubishi:	37.50%
Petronas Carigali:	25.00%

SK10

Nippon Mitsubishi:	75.00%
Petronas Carigali:	25.00%

Project Reserves

Gas (tcf):	6.9
Liquids (m.bbl):	141

Estimated FOB Resource Cost: $2.00-2.50/mcf

Supply

The SK8 and SK10 fields, currently under development will supply the MLNG Tiga plant, with first production slated for mid 2003. The SK8 acreage incorporates some 5.2 tcf of gas reservoired within several accumulations and SK10 incorporates 1.7 tcf of gas. SK8 and SK10 will be developed using drilling and processing platforms, one located on each block.

2.0. Atlantic Basin Supply Projects

Project: Camisea (Peru)

Field Status:	Under Development
Location:	Ucayali Basin, Central Jungle, 600 km east of Lima, Peru

Participants

Pluspetrol:	36.00%
Hunt Oil:	36.00%
SK Corp:	18.00%
Tecpetrol:	10.00%

Project Reserves

Gas (tcf):	5
Liquids (m.bbl):	346 (186 condensate +160 LPG)

Estimated FOB Breakeven Price Band: $2.50-$3.00/mcf

Supply

Cashiriari and San Martín, collectively known as the Camisea fields, are two large, gas/condensate discoveries. The Camisea fields remained undeveloped since their discovery by Shell in the mid-1980s due to their remote location and distance from potential markets. The fields were initially due to be developed by Shell and Mobil but, following failed negotiations with the Peruvian Government, both companies pulled out of the project in 1998. As part of the re-tendering process the government established a Camisea gas price agreement. The wellhead gas price cap has been set at $1.00/mmbtu for electricity generators and $1.80/mmbtu for industrial users. The re-tendered Camisea project has been divided into separate components, (production, transportation and distribution), specifically to avoid the possibility of vertical integration. As operator of the upstream component of the project, Pluspetrol plans a phased development of Camisea with Phase 1 incorporating liquids stripping and limited gas sales. Initial development facilities will have a capacity production rate of around 400 mmcfd of gas and 40,000 b/d of liquids. First drilling commenced in early 2002, with first production expected in early 2004.

Project: Pacifico LNG (Margarita) (Bolivia)

Field Status:	Under Development
Location:	Caipipendi Block, Tarija Basin, southeast Bolivia

Participants

Repsol-YPF:	37.50%
BG:	37.50%
Pan American:	25.00%

Project Reserves

Gas (tcf):	7.2
Liquids (m.bbl):	300

Estimated FOB Resource Cost: $2.00-2.50/mcf

Supply

The Margarita field was discovered in 1997 by the Margarita-X1 well, which tested 23 mmcfd gas. The partners have since drilled two appraisal wells, proving up gas reserves and resulting in the field becoming the largest gas accumulation in Bolivia. Repsol-YPF is planning a phased development of the Margarita field. Initially, this will consist of liquids stripping, with a later gas exploitation phase, when material markets have been established.

Full scale development will require up to 40 deep wells targeting the reservoir at 5,000 m depth. Although development drilling costs will be expensive this is counter balanced by a high liquids yield and excellent reservoir productivity. A pilot horizontal well is currently being drilled (a side-track of the discovery well) in an attempt to bring down the required number of wells.

Project: Sakhalin – 2 (Lunskoye) (Russia)

Field Status:	Under Development
Location:	Sakhalin Shelf

Participants

Shell:	55.00%
Mitsui:	25.00%
Mitsubishi:	20.00%

Project Reserves

Gas (tcf):	10.5
Liquids (m.bbl):	302

Estimated FOB Resource Cost: $2.00-2.50/mcf

Supply

The first phase of the development focused on early oil production from the Piltun-Astokhskoye field, which came onstream in July 1999. The second development phase encompasses the exploitation of the Lunskoye field, providing feedstock for the LNG project.

The Lunskoye field will be developed via a single platform, 13 kms from shore in a seasonal sea ice zone. Initially 30 long reach wells will be required. The hydrocarbons will then be piped 60 kms to an onshore processing facility.

Project: Angola LNG (Angola)

Field Status:	Onstream – Possible Development
Location:	Lower Congo Basin

Participants

ChevronTexaco:	32.00%
Sonangol*:	20.00%
BP:	12.00%
ExxonMobil:	12.00%
TotalFinaElf:	12.00%

*All gas owned by Sonangol

Project Reserves

Gas (tcf):	4.4
Liquids (m.bbl):	40

Estimated FOB Resource Cost: $1.50-2.00/mcf

Supply

Sonangol and ChevronTexaco began work on a potential LNG scheme for Angola in 1999. The participants for the Angola LNG project were finalised in March 2002, following discussions held by ChevronTexaco and Sonangol, and consist of several of the other major Angolan players with significant associated gas reserves, namely ExxonMobil, TotalFinaElf, BP and Norsk Hydro.

The supply for Angola LNG will be both associated gas from the offshore Lower Congo Basin fields, underpinned by several non-associated gas fields that exist in the shallow water regions of Blocks 1, 2 and 3. Gas from the various contributing fields will be connected to a central gathering hub (CGH) which is planned to be located on Block 2 in 43 metres of water near to the Atum field. The gathering hub will consist of a wellhead platform, riser platform, flare facilities, quarters and utilities platform. As production profiles change, future gas processing and compression platforms will be required. Non-associated gas will be partially dehydrated and have any H2S removed prior to joining the associated gas in the trunk line. The combined gas stream will be transported from the CGH to the proposed site for the LNG Plant via a 32", 250 km pipeline.

Project: Alba LNG (Equatorial Guinea)

Field Status:	Onstream
Location:	Equatorial Guinea

Participants

Marathon:	63.26%
Samedan:	33.74%
Equatorial Guinea State:	3.00%

Project Reserves

Gas (tcf):	4
Liquids (m.bbls):	70 LPG,
300 Condensate	

Estimated FOB Resource Cost: $1.00-1.50/mcf

Supply

Alba has been onstream since 1991 initially exploiting only the condensate plus small volumes of LPG, the remaining gas component was flared during this phase. In mid-1993, the capacity of the onshore processing plant was increased to handle production of circa 7,000 b/d of condensate and 90 mmcfd of gas. In January 1997, an upgrading of the LPG plant allowed up to 3,000 b/d of LPG to be extracted from the gas (plus an extra 400 b/d of condensate).

Phase 2 involved the construction of a local methanol plant, which came onstream in 2001. The sales agreement for the Methanol plant feedstock is valid for 20 years and requires gas reserves of 0.85 tcf. In addition small volumes (<5 mmcfd) are also utilised for power generation on Bioko Island, equating to 0.1 tcf over the project life and 0.35 tcf will be flared. Estimates for total gas reserves in the Alba received a huge upgrade following the Alba-9 appraisal well, which was drilled in May 2001. The well encountered a net bearing reservoir of more than 200 metres in thickness. Stated reserves for the Alba field are now 5.4 tcf and more than 300 m.bbl of condensate and 70 m.bbl of LPG, thus leaving 4.1 tcf of gas currently uncontracted. In addition to the Alba field, the Alba licence also contains the Estrella gas/condensate discovery (500 bcf), which was made in early 2001, and the potential for further discoveries is thought to be high.

It is understood that an LNG facility is Marathon's preferred option to monetise its significant remaining gas reserves. The upstream project economics benefit from the excellent well productivity, shallow water location and significant liquids driven revenue.

Project: NLNG Plus (Nigeria)

Field Status:	Onstream
Location:	Onshore/Shallow Water, Niger Delta, Nigeria

Participants

NNPC:	30.00%
Shell:	10.00%
TFE:	5.00%
Agip:	55.00%

Gas also sourced from the Bonga SW and Amenam fields

Project Reserves

Gas (tcf):	9
Oil (m.bbl):	9,925 (remaining on Shell JV)

Estimated FOB Resource Cost: $1.00-1.50/mcf

Supply

The feedstock supplying Trains 4 and 5 will be sourced from new Shell, Agip and TFE JV onshore developments and also the offshore TFE operated Amenam field and the deepwater Shell operated Bonga SW field. The upstream supply economics benefit from being exempt from royalty payments and the associated gas capital costs are deductible against PPT.

Project: Brass River (Nigeria)

Field Status:	Onstream – Probable Development
Location:	Onshore/Shallow Water, Niger Delta, Nigeria

Participants

NNPC:	60.00%
Agip:	20.00%
ConocoPhillips:	20.00%

Project Reserves

Gas (tcf):	5.5
Oil (m.bbl):	965 m.bbl

Estimated FOB Resource Cost: $1.50-2.00/mcf

Supply

The feedstock for the initial train at Brass River will be supplied from the Agip operated JV utilising both associated and non-associated fields. Upstream economics benefit from the gas revenue being exempt from royalty payments and that the associated gas capital costs are deducible against PPT.

Project: Nnwa-Doro (Nigeria)

Field Status:	Technical Reserves
Location:	Deepwater, Niger Delta, Nigeria

Participants

OPL 218	
Statoil:	26.92%
ChevronTexaco:	23.08%
Agip:	6.25%
OPL 219	
Shell:	27.50%
ExxonMobil:	10.00%
TFE:	6.25%

Assumes a 50/50 unitisation split

Project Reserves

Gas (tcf):	5.25
Liquids (m.bbls):	

Estimated Resource Cost: $2.50-3.00/mcf

Supply

A number of free gas discoveries have been made in the deepwater sector since exploration commenced in the area in the early 1990s, the most significant being the Nnwa-Doro field. Like many free gas reserves in Nigeria, Nnwa-Dora has remained undeveloped because the focus of most gas commercialisation projects is to harness the associated gas, which is currently being flared.

The Nnwa-Doro gas field (5 tcf) extends across the Nigerian deepwater blocks OPL 218 and OPL 219. The Nnwa field was discovered in block OPL 218 in February 1999. The extension of the structure into block OPL 219 was confirmed as the Doro discovery in September 1999.

The Nnwa field is currently undergoing appraisal with a development decision expected in late 2003. The scenario modelled envisages the fields will be developed via sub-sea wells tied back to a turret moored weather-vaning FLNG barge.

Project: Gassi Touil Integrated Gas Project (Algeria)

Field Status:	Technical Reserves
Location:	Berkine Basin, Southeast Zone, Algeria

Participants

Sonatrach:	100%

Project Reserves

Gas (tcf):	3.6
Liquids (m.bbl):	220

Estimated FOB Resource Cost: $2.50-3.00/mcf

Supply

The Gassi Touil Integrated Gas Project was announced in early 2002 as an opportunity for companies to participate in an integrated project which will include the development of the field, gas marketing rights and a new LNG Plant. There are seven fields included in the package, namely Gassi Touil, Nezla, Hassi Touareg, Toual, Brides, Nezla Nord, Gassi El Adem. The first four fields have been producing, whereas the latter three are undeveloped. The fields are located 100 kilometres north of the Rhourde Nouss field in the Berkine basin.

Sonatrach has split the timetable for tender into technical and commercial stages. Companies had until December 2002 to submit technical proposals and economic proposals (including government take) by April 2003, with awards expected in July 2003. Thus at this stage the final participation in the development is unknown.

The upstream scenario modelled assumes the gas, post processing, is piped northwards to Arzew utilising capacity in the existing Sonatrach pipelines. Wood Mackenzie has assumed the upstream element is tax under existing harsh PSC terms.

Project: ELNG I&II (Egypt)

Field Status:	Under Development
Location:	West Delta Deep Marine PSC, Nile Delta, Egypt

Participants

EGPC/EGAS:	50.00%
BG:	25.00%
Edison:	25.00%

Equity paying partners BG 50% and Edison 50%

Project Reserves

Gas (tcf):	7.9 tcf
Liquids (mmbbl):	105 (Sapphire field only)

Estimated FOB Resource Cost: $1.00-1.50/mcf

Supply

The Sapphire, Sienna, Simian, P12/13 gas fields are located in the West Delta Deep Marine (WDDM) PSC off Egypt's Mediterranean coast. The Sapphire field has recoverable reserves of 4.3 tcf gas and 105 mmbbl condensate and will require separate pipeline infrastructure to that of the Scarab-Saffron dry gas fields currently under development on the block. Of the other three dry gas fields, Simian is the largest with 4.5 tcf gas.

BG and Edison have over-engineered the gas infrastructure for the development of their Scarab-Saffron fields, currently supplying the domestic market, thereby reducing the incremental cost of development on WDDM and making the remaining assets very attractive as a competitive source of supply for any LNG export project.

Train I will be supplied by the Simian and Sienna fields; Train II will be sourced by the Sapphire field.

Project: Snøhvit (Norway)

Field Status:	Under Development
Location:	Barents Sea, Norway

Participants

Norway State DFI:	30.00%
Statoil:	22.29%
TFE:	18.40%
GdF:	12.00%
Norsk Hydro:	10.00%
Amerada Hess:	3.26%
RWE-DEA:	2.81%
Svenska Petroleum:	1.24%

Project Reserves

Gas (tcf):	4.6
Liquids (m.bbls):	160

Estimated FOB Resource Cost: >$3.00/mcf

Supply

The Snøhvit upstream feedstock will be sourced from three gas condensate fields, located 140 kms north-west of the planned liquefaction plant at Melkøya. The Snøhvit and Albatross fields will be developed in the first phase, with the Askeladd field expected to be brought onstream in a later phase, some 12 years after start-up.

The field will be exploited by a sub-sea development with the gas and condensate piped 160 kms onshore via a 27” multi-phase line. Onshore the gas will be processed, stripping out the liquids, water and CO_2, which will be re-injected.

Project: Atlantic II & III (Trinidad)

Field Status:	Onstream-Under Development
Location:	Columbus Sub-basin and West Tobago Basin, Trinidad

Participants

East West Blocks	
BP:	70.00%
Repsol-YPF:	30.00%
NCMA	
BG:	45.90%
PetroTrin:	19.50%
Agip:	17.30%
Petro-Canada:	17.30%

Project Reserves

Gas (tcf):	7.2
Liquids (m.bbl):	316 (East West Blocks)

Estimated FOB Resource Cost:
$1.00-1.50/mcf (East West Blocks Feedstock),
$1.50-2.00/mcf (NCMA Feedstock)

Supply

Train II will source 50% of the feedstock from BP’s operated East & West Blocks and 50% from BG’s North Coast Marine Area (NCMA). BP will supply the majority (75%) of Train III feedstock with BG supplying the remaining balance of 25%.

The BG operated NCMA has been on production since last year. The block encompasses 5 dry gas fields, which are undergoing a phased development. The initial fixed jacket, drilling, processing and accommodation platform is located on the Hibiscus field. The remaining fields will be exploited via sub-sea tie backs or by separate well head platforms.

BP are currently developing the Kapok complex which will be the primary source for LNG feedstock, from 2003 onwards. The complex comprises 3 gas condensate fields, Sparrow, Renegade, and Parang. Phase I of the development will exploit the Sparrow and Renegade fields, utilising an unmanned wellhead platform located over the Sparrow, Renegade fields. A large central, processing unit will be installed at the Cassia field which will serve the current Kapok development and other subsequent developments such as the Mango, Cashima and Iron Horse fields. The gas post processing will be piped to shore via a new dedicated 48” line, which has been oversized to accommodate future new developments.

Project: Mariscal Sucre LNG (Venezuela)

Field Status:	Probable Development
Location:	Magarita Basin, off the Paria Peninsula, Eastern Venezuelat

Participants

PDVSA:	49.00%
Shell:	32.00%
QGPC:	9.00%
Mitsubishi Corp.:	8.00%
Local investors:	2.00%

Project Reserves

Gas (tcf):	5.1
Liquids (mmbbl):	50

Estimated Resource Cost: $1.50-2.00

Supply

The Patao, Dragón and Mejillones (all non-associated gas fields) and Río Caribe (a gas/condensate field) were discovered between 1978 and 1981, and together are thought to hold around 11 tcf of gas. Following one previously unsuccessful attempt to launch an LNG project, involving Shell, Exxon and Mitsubishi the project was re-tendered in October 2001, with PDVSA, Shell and Mitsubishi setting a new scope for the development of the Mariscal Sucre LNG project. The project will develop the aforementioned gas fields targeting primarily the LNG export market but also the domestic gas market.

The fields will be developed via a series of wellhead platforms on each field supplying a central processing platform, from which the gas will be piped to shore via a 30" line. The LPGs will be stripped onshore prior to the gas being liquefied.

3.0. Middle East Supply Projects

Project: Qatargas Expansion (Qatar)

Field Status:	Onstream – Probable Development
Location:	Qatar Arch

Participants

Train 4

Qatar Petroleum:	65.00%
TotalFinaElf:	20.00%
ExxonMobil:	10.00%
Repsol-YPF*:	2.50%
ENEL*:	.50%

*Assumes Repsol-YPF and ENEL will back into the upstream

Trains 5 and 6

Qatar Petroleum:	70.00%
ExxonMobil:	30.00%

Project Reserves

Gas (tcf):	8.8
Liquids (m.bbl):	380

Estimated FOB Resource Cost: $1.00-1.50/mcf

Supply

The North gas field is the largest free gas accumulation in the world. For the purposes of commercial development it has been divided into development areas, each comprising 10 kilometre squares. To date there are five sanctioned areas within the field: North Field Alpha, Qatargas, RasGas, Dolphin and the Enhanced Gas Utilisation (EGU) project. These projects are dedicated to meeting domestic requirements (North Field Alpha), two LNG projects (Qatargas and RasGas) and delivering gas supplies to local and regional markets (Dolphin and EGU). Wood Mackenzie believes the existing Qatargas upstream sector has sufficient reserves to supply the feedstock for Train 4, assuming additional wellhead platforms and export lines are constructed. Trains 5 and 6 feedstock will require a new dedicated sector of the North Field, again exploitation will require new well head platforms and an export gas line.

Project: Iran LNG (Iran)

Field Status:	Probable Development
Location:	Arabian basin

Participants

Various projects are under discussion:

Iran LNG
Pars LNG
Persian LNG
NIOC LNG
BP
TFE

Shell
NIOC

Project Reserves

Gas (tcf):	8.8
Liquids (m.bbl):	380 per phase

Estimated FOB Resource Cost: $1.00-1.50/mcf

Supply

The South Pars field is the eastern half of the field known as the North (Dome) field in Qatar and is the world's largest free gas accumulation. Field development will be undertaken in a number of phases, of which numbers 1-5 and 9 and 10 are intended to supply the Iranian industrial, power and domestic gas markets, whilst Phases 6-8 are planned as supply for injection to enhance production and recovery in the giant onshore Agha Jari oil field. Phases 11 and 12 have been allocated as source gas for the planned Iran LNG project and this is currently under negotiation with a number of competing international consortia.

Due to the huge scale of the gas resource, high well productivities and the relatively benign operating environment, capital and operating costs will be low (similar to that in the North field in Qatar). Reservoir performance uncertainties have also been reduced given the number of appraisal wells that have been drilled in both the Iranian and Qatari sectors.

Project: Oman LNG Expansion (Oman)

Field Status:	Onstream/Under Development
Location:	Central Oman Sub-basin

Participants

Government of Oman*	100.00%

*Government of Oman (60%), Shell (34%), TotalFinaElf (4%) and Partex (2%)

Project Reserves

Gas (tcf):	7
Liquids (mmbbl):	340

Estimated FOB Resource Cost: $1.00-1.50/mcf

Supply

The Saih Rawl and Barik gas fields which came onstream in June 1999 and August 1999 respectively supply the feedstock to Trains I and II. Train III feedstock will be supplied by the completion of another zone in Saih Rawl field and the full development of the adjacent Saih Nihayda field.

Currently the Train I and II feedstock undergoes primary processing at the Barik field, whilst liquids are stripped at the Saih Rawl facilities. The processed gas is then piped 360 kms north to the liquefaction plant. The train III development will require additional processing facilities at Saih Nihayda and the construction of a 48" pipeline linking into the existing export line.

Project: Yemen LNG (Yemen)

Field Status:	Technical Reserves
Location:	Marib-Shabwa Basin

Participants

Marib-Jawf*	
Yemen Gas:	60.00%
YEPC^:	30.00%
Yemen LNG:	10.00%

*Participation post expiry of existing contract in 2005

^YEPC comprises the existing partners Exxon-Mobil, Hunt, SK Corp et al.

Reserves

Gas (tcf):	3.4
Liquids (m.bbl):	1,264 (Remaining reserves on the Marib-Jawf block)

Estimated Resource Cost: $1.50-2.00/mcf

Supply

The Marib-Jawf contract and to a lesser degree the adjacent Jannah contract contain the vast majority of natural gas reserves (both associated and free) discovered in Yemen. The largest gas field is the Al Raja field, which is located in the Marib-Jawf contract and has free gas reserves estimated at 3.5 tcf. Total 2p reserves in the area are estimated at 19 tcf.

Gas from the Marib-Jawf and the Jannah contract areas has been slated as a potential feedstock source for the proposed Yemen LNG project. The LNG group would be responsible for the construction of the gas gathering and processing infrastructure and the building of the 360 kms export gas line to the liquefaction plant.

APPENDIX D

COMPRESSED NATURAL GAS

There are sizable untapped natural gas reserves throughout the world. Those not close enough to markets to be economically produced and transported through a pipeline are often referred to as "stranded" and must be processed and transported using alternative methods of delivery. The challenge is to design and implement safe, reliable, and economic alternatives to pipeline delivery.

Three potential alternatives of natural gas development include LNG, GTL, and CNG. Liquefied natural gas (LNG) undergoes a phase change from a gaseous to a liquid state at cryogenic temperatures. The LNG chain, however, is a massive, capital-intensive series of operations best suited for large-volume reserves that can take advantage of economies of scale.

Converting natural gas to a liquid using so-called "Gas-to-Liquids" (GTL) technology is a future potential development for stranded gas reserves. This technology transforms the gas into a liquid at ambient conditions. Although this technology has yet to be commercially employed, it is a potential competitor with LNG for developing stranded gas resources.

Compressed natural gas (CNG) marine transport technology, a relatively low-tech alternative, involves dehydration, condensate removal, cooling, and compression of the natural gas into a specially designed containment system of pipes or tubing. This alternative may be a better solution for smaller-sized reserves that are located a relatively shorter distance to the market.

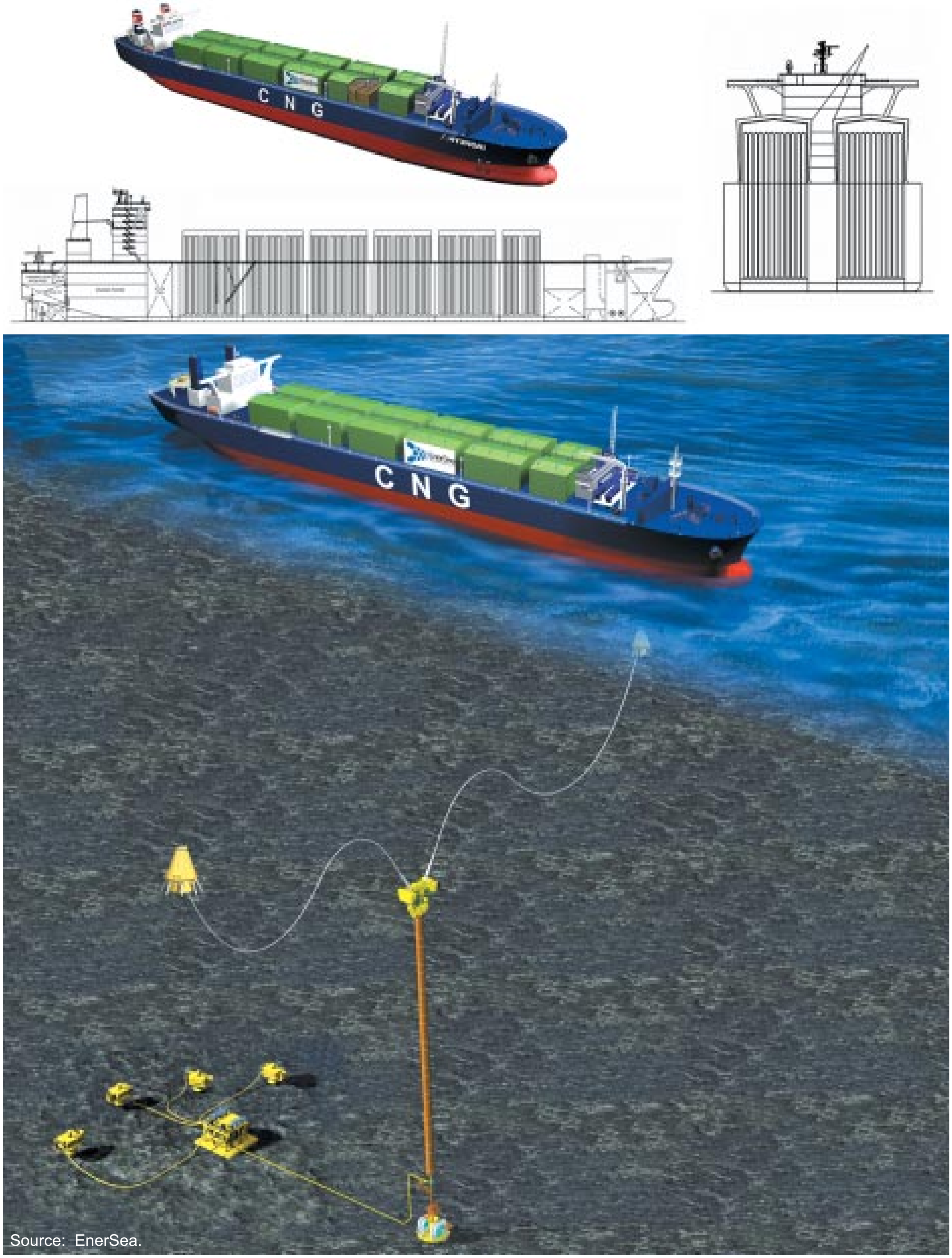
The CNG process cools the natural gas to temperatures below 32°F and compresses it at high pressure (from 1,000 to over 3,000 psi). This makes it possible to load large quantities of natural gas (conceptually between 30 million and 1.5 billion cubic feet, depending upon the system used) into a carrier. The storage containment is integrated into a barge or ship of varying size depending on the application. Increasingly higher gas storage pressures will require correspondingly stronger, heavier and more expensive containment systems. The technical challenge is to optimize the design, taking into account the weight of the containment system, gas quantities, size, and speed of the carrier, as well as other factors in order to provide the most cost-effective transportation system.

CNG technology is still in a process of evolution, although considerable advancements have been recently achieved. A few of the more advanced concepts that are being developed for commercial application are:

- **Williams (Coselle) –** incorporating spools of coiled tubing.
- **Knutsen (PNG) –** using high-pressure steel pipes.
- **Trans Ocean Gas –** using resin and fiber composite pressure vessels.
- **EnerSea (VOTRANS) –** using bundles of steel pipes containing the gas under optimized pressure and temperature.

Diagrams of the VOTRANS™ design are shown in Figure D-1 and representations of the Coselle system are shown in Figure D-2.

As shown in Figures D-3 and D-4, the loading and discharging of the compressed natural gas could be performed offshore from proven buoy-type transfer systems connected to the offshore production platform



Source: EnerSea.

Figure D-1. VOTRANS

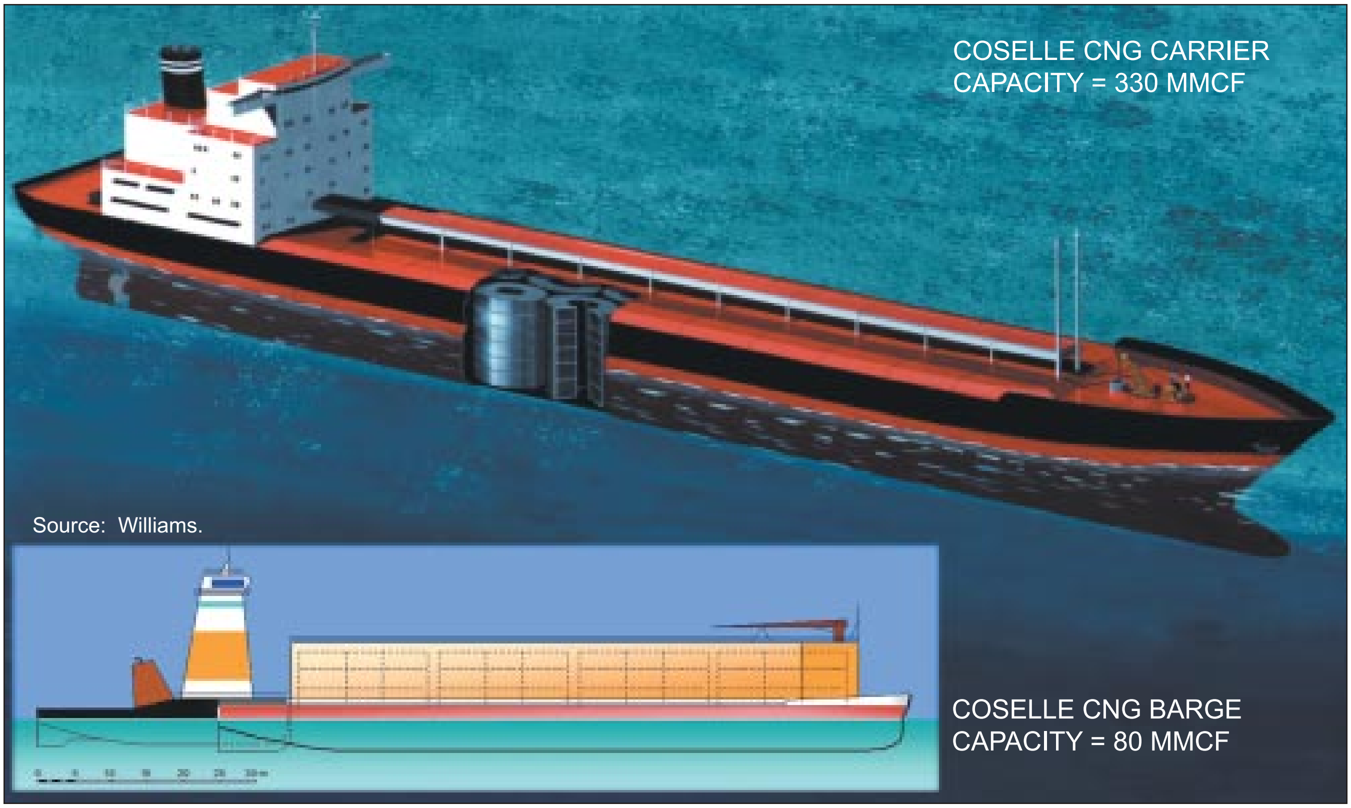


Figure D-2. Coselle

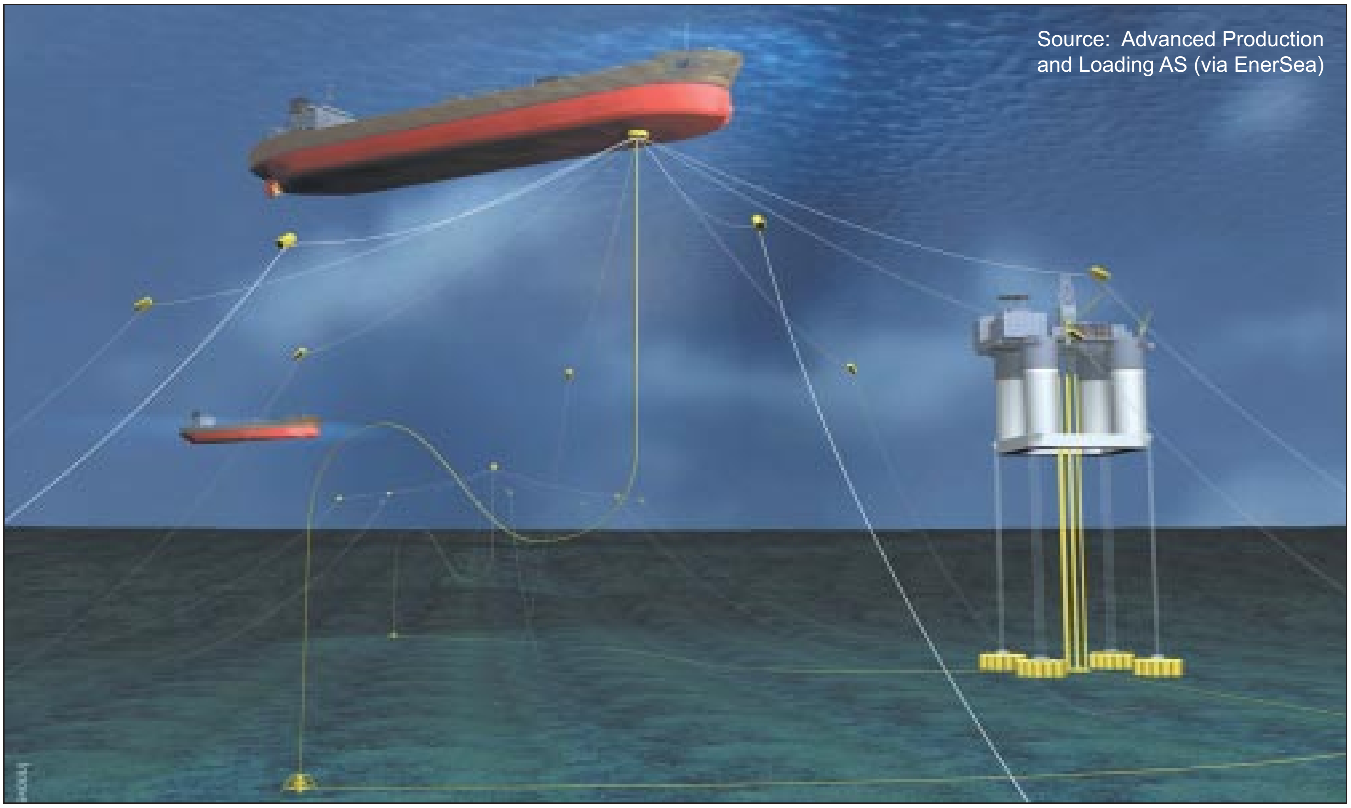


Figure D-3. CNG Carrier Loading Near Offshore Production Facilities

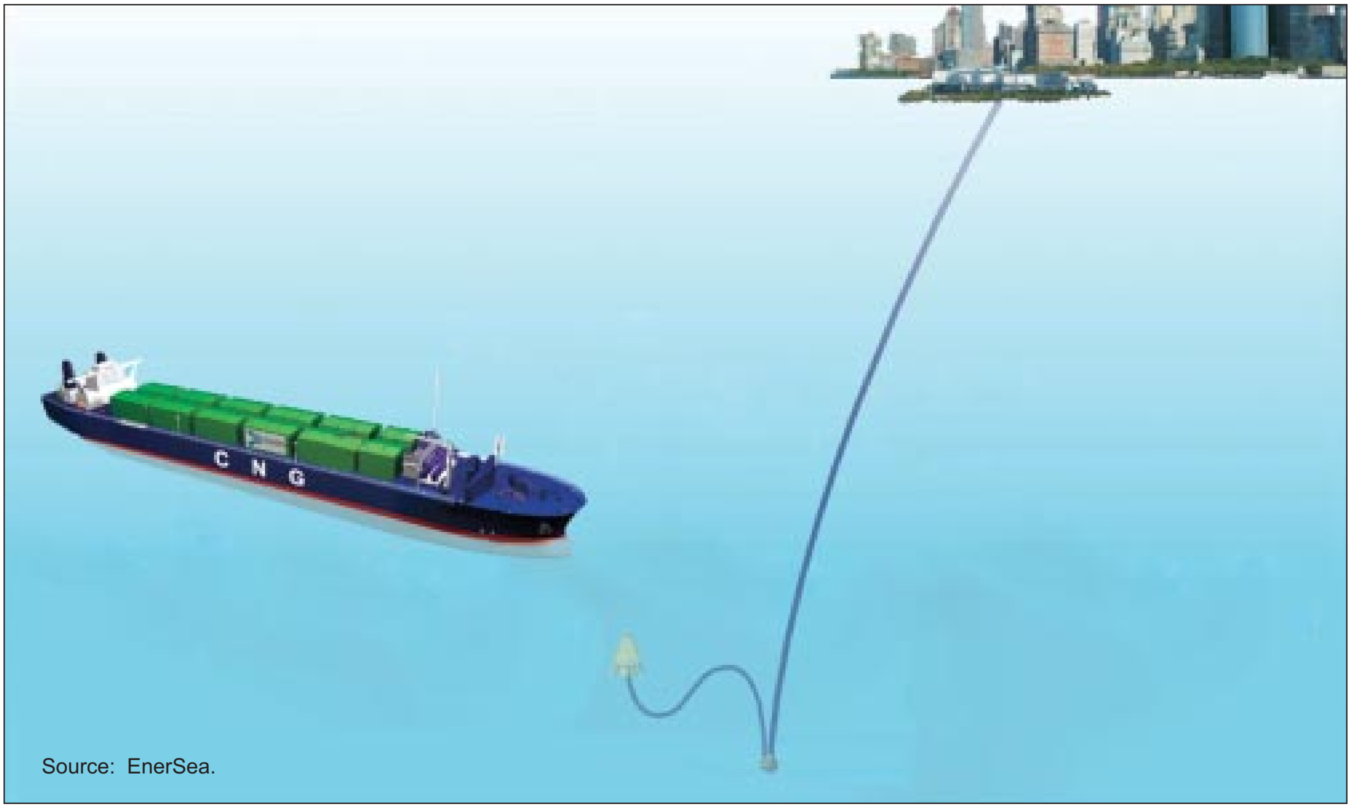


Figure D-4. Safe and Secure Offshore CNG Deliveries

via short subsea pipelines. Similar submerged buoy-type terminals would be located safely offshore near the market and connected to the gas pipeline or distribution line at the delivery location. The use of such loading and unloading schemes provides cost-effective transportation in deepwater conditions where pipelines are not viable. In addition, the systems may be designed for either "batch" loading (i.e., one gas carrier at a time) or continuous loading using twin buoys at the loading and delivery points. The total capital investment in loading and unloading infrastructure is considerably less than that of a conventional LNG project, especially considering that no storage tanks other than the shipboard containment systems may be required.

Although many factors will influence the cost of CNG, the cost of CNG transportation service is expected to range between $1.50 and $2.50 per MMBtu. Most of that expense is related to the CNG vessel. Depending on the technology employed, ancillary equipment required, etc., the cost for the largest CNG carrier is expected to exceed that of a standard sized LNG carrier, which is about $160 million. CNG vessels, however, are only able to load a fraction of the quantity of natural gas that a typical LNG carrier delivers (1+ billion cubic feet of gas for the largest current designs for CNG carriers compared to 3.0 billion cubic feet equivalent for today's LNG carriers). This apparent disadvantage is offset by the fact that CNG does not require large capital investments in liquefaction and regasification facilities at the loading and delivery points. For CNG, about 85% of the capital cost is for the carriers and 15% for the terminal and related equipment. The lack of extensive terminal facilitiy requirements allows the CNG technology be deployable in a broader array of geographic conditions than LNG. And the considerably smaller offshore loading and unloading pipelines and buoys make for a less intrusive infrastructure that would tend to reduce opposition to siting. Finally, the variable costs of fuel used for liquefaction and boil off for LNG far exceed the minimal quantities used in compression of CNG (15-25% for LNG versus less than 5% for CNG).

Marine CNG technology is expected to develop into an effective niche application to complement LNG. Its advantages allow it to be deployed in situations where the size of the natural gas reserves being developed are either known to be limited or in an early development stage and not yet suited for large-scale LNG application. If the reserves are being produced from a deepwater environment such that traditional pipeline methods cannot be employed and the market for the gas is located in reasonably close proximity to the production, then the technology's commercial and economic advantages is apparent. Areas where marine CNG is currently expected to be viable for transporting natural gas production include the deepwater Gulf of Mexico, the Caribbean, the Mediterranean, Atlantic Canada, and Southeast Asia (see Figure D-5).

While a great deal of development work has been completed, there are a number of challenges still to be met before the first CNG project is realized. Approval of various carrier design concepts and establishment of industry codes and standards is currently underway. Containment, piping, transfer systems, safety, and monitoring systems must all be thoroughly considered and approved. For example, the EnerSea VOTRANS ship design received its "class approval in principle" from the ABS ship classification society in April 2003. Approvals in principle have also been granted for the Knutsen PNG and Williams Coselle designs. Operating procedures must still be examined and approved by various agencies including the USCG, FERC, MMS, EPA, and COE. State and local agencies may also participate in the process. The Jones Act, which imposes restrictive regulations on transportation operations between U.S. ports, will also be an obstacle to the viability of CNG in regions such as the Gulf of Mexico. Insurance and financial companies also must be satisfied with the technology before investors will support its application. Finally, the CNG promoters must convince potential EP developers of the business case for CNG, including its safety, integrity, and reliability, before the technology will be widely implemented.

The framework for the application of marine CNG technology has been established; the credibility of the designs is being tested and approved in principle; improvements to the commercial and economic aspects are being made; and progress is also being made with designers and shipyards to hone delivery schedules and advance toward project execution. Given this momentum and the need for innovative solutions to bring new natural gas reserves to market, the prospects for the application of marine CNG technology appear good.

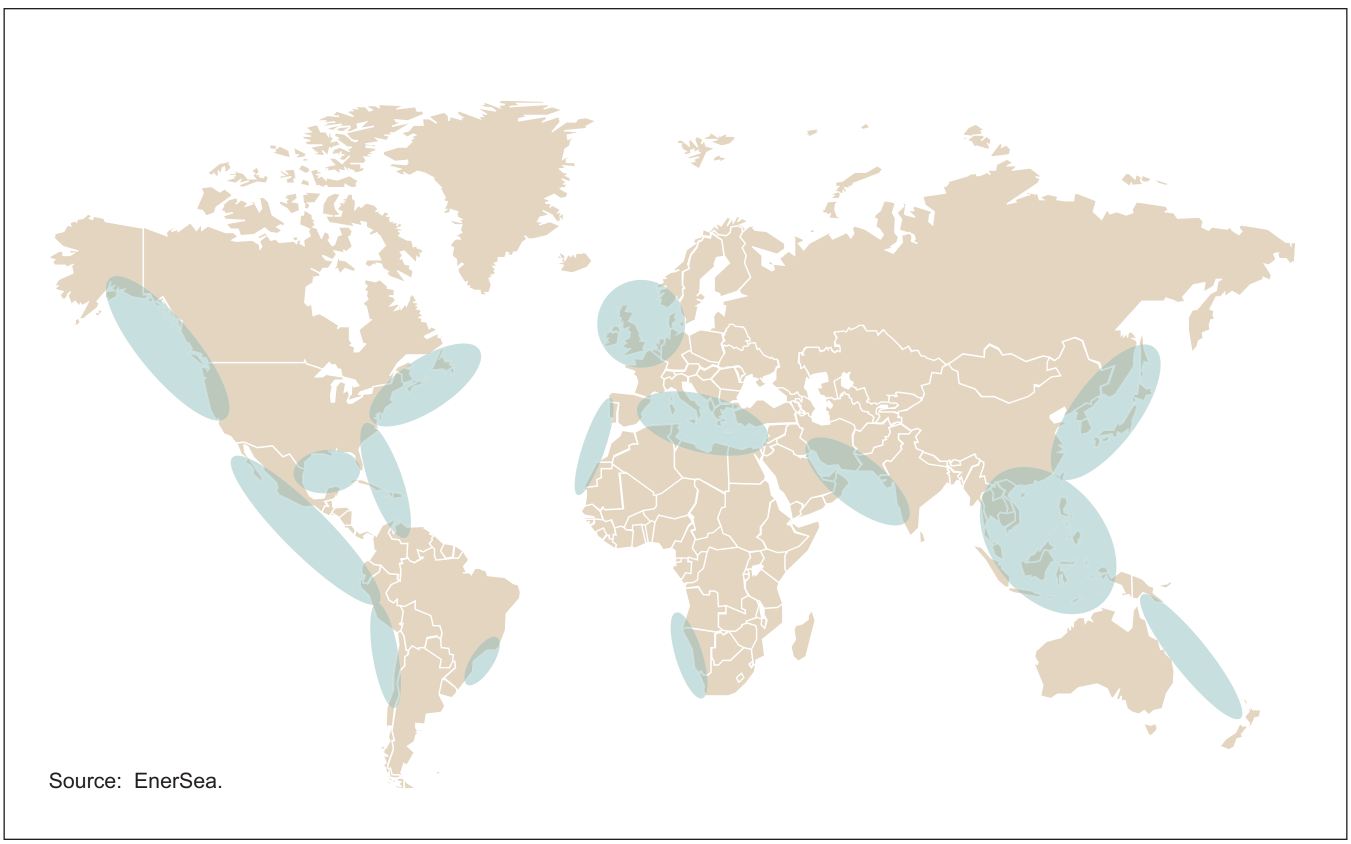


Figure D-5. Prospective CNG Source/Market Areas

APPENDIX E

LNG INTERCHANGEABILITY

Liquefied natural gas (LNG) is expected to represent an increasingly larger portion of future natural gas supplies for the U.S. market. Global LNG supply comes from many sources, is not homogeneous, and has heating value contents that vary widely. This wide variation in heat content means that some LNG streams may not be fully interchangeable with the existing U.S. natural gas pipeline system.

A key consideration for importers of LNG is the degree to which the regasified LNG is "interchangeable" with pipeline gas. The ISO definition of Natural Gas Interchangeability is the measure of the degree to which the combustion characteristics of one gas resemble those of another gas. Two gases are said to be interchangeable when they can be substituted under the same conditions without affecting the performance of the gas burner.

The interchangeability of LNG is an important issue to consider, as the composition of imported LNG can be different from that of current domestic pipeline gas. That difference is not because the composition of the gas produced in North America differs from natural gas in other parts of the world, but is more of a result of the rise of the ethane-based petrochemical industry. As the petrochemical and natural gas liquids (NGL) industries developed in the United States, the typical heating values of the "natural gas" being delivered to the interstate pipeline and end-use markets decreased markedly due to increased recovery of ethane, propane, and butane, which were then sold as separate products. As the U.S. gas infrastructure developed and matured, the system delivered leaner pipeline gas (gas with less heavier hydrocarbon constituents and lower heating value). In most other regions of the world, natural gas is not subjected to such high levels of ethane and propane extraction, resulting in higher heating values for pipeline gas.

LNG production plants are usually located in remote areas with limited or no local ethane markets. Thus few LNG production plants extract ethane from its feed. Propane and butane, on the other hand, are extracted at varying levels based on the economic value of those products at the specific LNG plants. As a consequence, most LNG contains more ethane, propane, and butane than U.S. domestic pipeline gas, as shown in Figure E-1. Furthermore, LNG contains virtually no carbon dioxide and little or no nitrogen, both of which are commonly present in domestic natural gas.

The presence of hydrocarbons heavier than methane (ethane and propane) and low levels of non-hydrocarbons result in most LNG supplies having a gross heating value between 1,100 and 1,150 Btu per cubic foot (Figure E-2) or about 10% higher than that of typical U.S. domestic pipeline gas.

Many of the U.S. gas pipelines have heating value specifications that serve to protect the pipelines and the markets they supplied from the presence of liquid hydrocarbons in a distribution system designed to handle a gas-only stream. It should be understood and appreciated that LNG contains negligible quantities of pentanes and heavier, which are the natural gas components most likely to create a liquid phase in a pipeline. LNG has generally no more than 0.1% of pentane-plus because, if present in greater quantities, these compounds will freeze in the liquefaction process and plug the heat transfer equipment in the coldest parts of the plant.

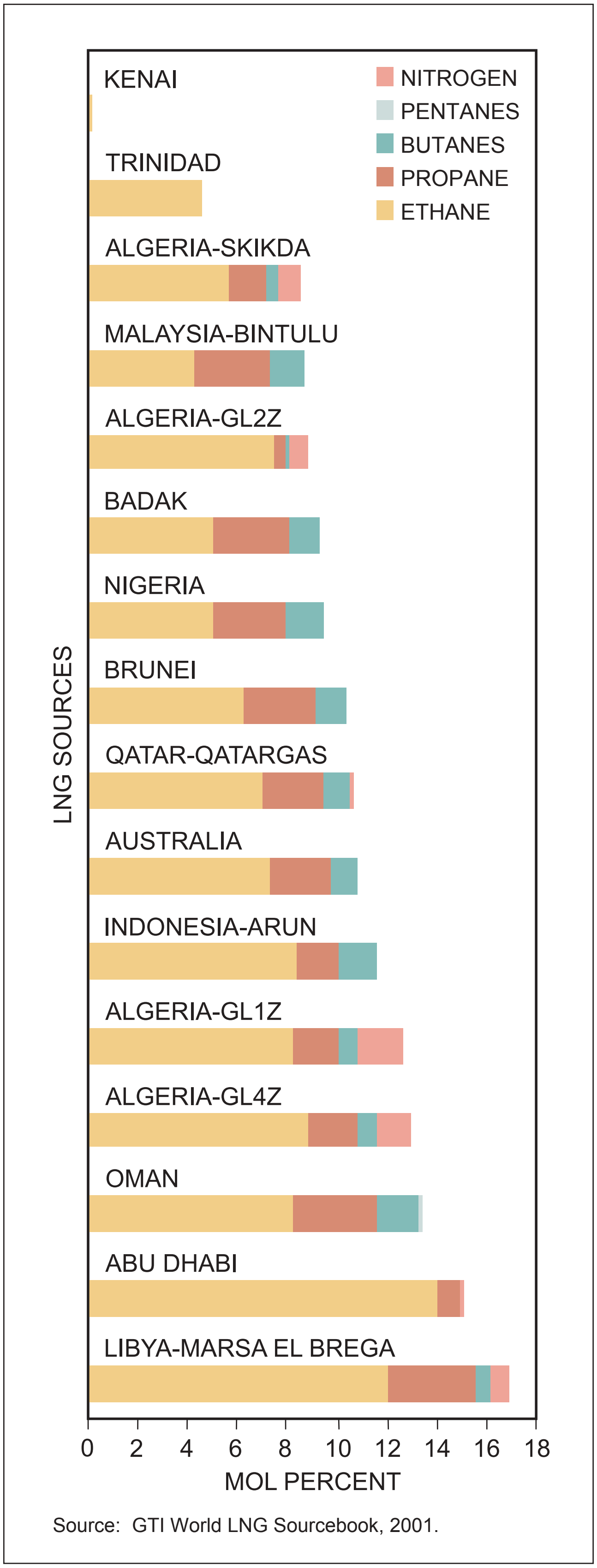


Figure E-1. Non-Methane Constituents for Selected LNG Export Plants

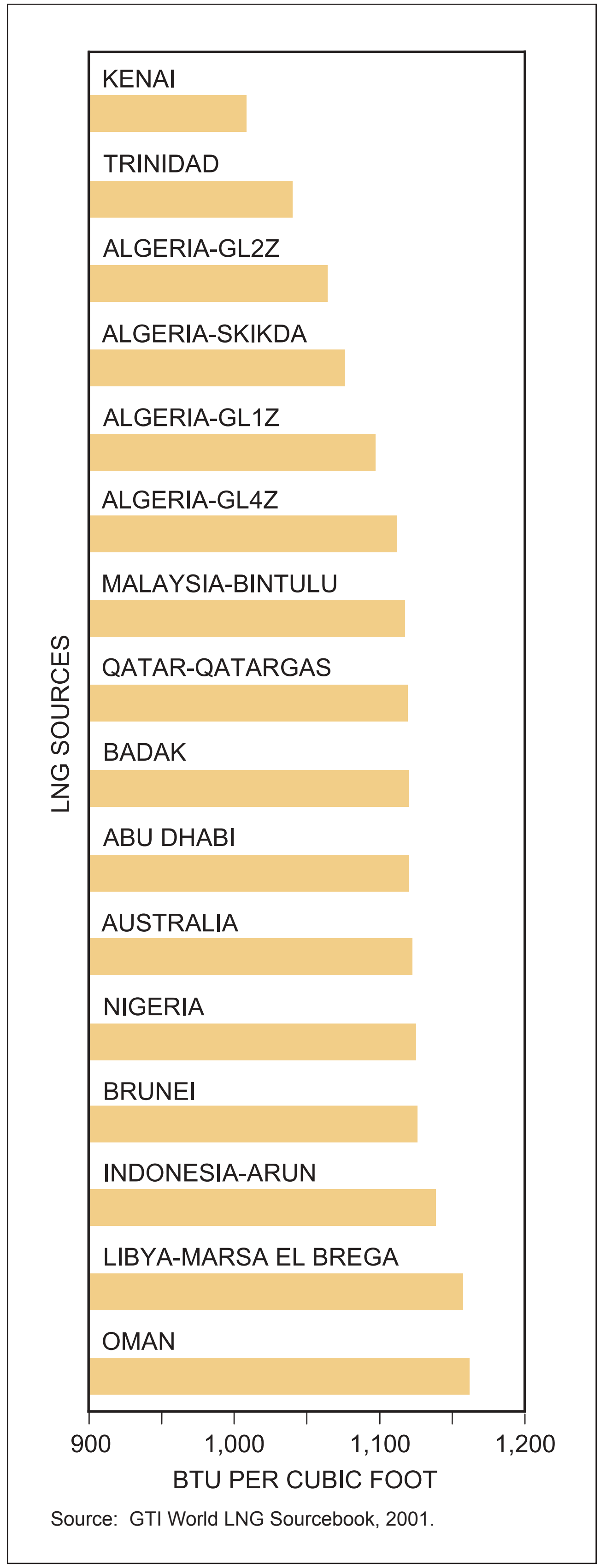


Figure E-2. LNG Energy Content for Selected LNG Export Plants

The introduction of LNG is a concern to pipeline operators and utilities if the regasified LNG is not interchangeable with domestic pipeline gas.[1] The potential consequences of some sources of LNG could include:

- A change in the performance of gas-fired appliances that may result in the incomplete combustion of the gas at the burner and the formation of unsafe levels of carbon monoxide in the exhaust gas.
- Increased NOx emissions, which is an important environmental concern
- The need to modify plant equipment for certain process gas users
- Knocking in gas engines that are tuned to burn typical pipeline quality gas
- Upsets in process controls and effects on the accuracy of metering equipment set to measure lower heating value gas.

Fortunately, there are ways to address interchangeability that can make the introduction of LNG into the pipeline system practically seamless. It involves an understanding of the underlying issue along with the appropriate preparation and close involvement of all the affected parties.

If the composition of imported LNG requires adjustment to enhance its interchangeability with U.S. pipeline gas, one or more of the following may be utilized:

- Dilution of richer regasified LNG with inert gases such as nitrogen
- Extraction of the ethane, proprane, and butanes at the LNG import location prior to delivery into the gas pipeline infrastructure
- Extraction of ethane, propane, butanes, and residual pentane-plus components at the LNG liquefaction and export facilities prior to shipping to the United States
- Blending of richer LNG with leaner LNG at the U.S. LNG import terminal
- Blending of richer vaporized LNG with leaner pipeline gases downstream of the U.S. LNG import terminal.

In addition to the possible modification of the composition of the natural gas stream, the U.S. market must reassess its current tariff specifications regarding gas quality. As noted, most segments of the U.S. gas grid have been receiving a relatively homogeneous domestically supplied natural gas. Many other gas markets in the world already receive their supplies from diversified sources including local production, pipeline gas, and LNG. For example, the European gas markets have a national gas quality specification based on an acceptable Wobbe Index range. Test conditions for new gas burning appliances are aligned with those specifications.

In the United States, gas quality specifications have been established on a pipeline-by-pipeline basis. Most gas quality specifications are based on the composition of the gas rather than more relevant combustion characteristics. This most often has resulted in unnecessarily restrictive compositional and gross heating value limits that have little relevance to the interchangeability of gas. Such restrictive tariff provisions limit the supply options available to the U.S. market. Some pipeline tariffs do not include a maximum gross heating value specification but rather rely on a generic "merchantability" standard which leads too much uncertainty. A comprehensive review of the gas quality specifications and adoption of more meaningful interchangeability parameters such as the Wobbe Index would provide the U.S. gas market greater access to the diverse, worldwide LNG supplies.

The current ANSI standards for testing gas-fired furnaces calls for using gas with a heating value of 1,075 Btu per cubic foot, within the range for many LNG sources. However, due to the increased stripping of heavier components, the typical heating value of pipeline gas today is significantly lower, ranging between 1,025 and 1,060 Btu per cubic foot in most regions of the country.

Technically it is possible to produce lean LNG with a lower heating value, but at a cost. Those costs will vary at each production plant. Costs will be high for LNG plants with significant existing production capacity that have historically been targeted for markets requiring high heating value LNG. These facilities will require separate fractionation, liquefaction, and LNG

[1] "LNG's Lack of Consistent Composition Hinders US Importers, Raising Question of the Need for Global Standard," LNG Express, Volume XII, No.11, November 2003.

storage to be built to be able to produce lean LNG as well as rich LNG. Costs may also increase if the gas supply contains a significant amount of ethane. If the ethane cannot be left in the LNG or blended into the rich LNG product, then, due to lack of a local ethane market, it will have to be sold as a waste product. Those costs can be significant, making supply of a lean LNG economically unattractive for most of the existing LNG producers. Tight specifications on maximum heating value for the U.S. market may significantly limit the LNG supply options.

Some liquefaction facilities, such as Atlantic LNG in Trinidad and Tobago and Nigeria LNG, have installed liquifiable extraction facilities that removes significant portions of ethane and heavier components as part of the production process. The resulting LNG is similar in heating value to U.S. pipeline gas.

The picture for extraction at the LNG import terminal is similar, i.e., technically possible, but costly. It requires fractionation columns and storage and handling facilities for separate ethane, propane, butanes, and pentanes-plus products. The sales value for ethane, whose composition most closely resembles methane of all the natural gas liquifiables, will only exceed the cost of extraction if a local ethane market exists or if the ethane can be delivered economically into a pipeline that accepts ethane. The separate product export of extracted propane, butane, and heavier natural gas liquifiables by pipeline, ship, truck, or train may be an issue for the local community.

Although the heating value puts strict limits on the LNG supply options, it is actually not the preferred interchangeability measure. A significant amount of research is available, which shows that the major interchangeability issues – such as incomplete combustion and resulting carbon monoxide formation, NOx emissions, and flame lift – correlate much better with the Wobbe index than with the heating value. The Wobbe index is the gross heating value corrected for the relative density: Wobbe index = GHV/(relative density)$^{-0.5}$. Outside the United States, gas quality specifications are primarily based on the Wobbe index rather than heating value.

Interchangeability research in the United States started as early as the mid-1900s, when the U.S. Bureau of Mines and American Gas Association (AGA) Labs conducted extensive studies on gas interchangeability. This work led to the development of a group of indices for determining fuel interchangeability on residential burners fired with natural gas and certain representative manufactured gases. "Acceptable" ranges were then established for several key indices. If the gases being compared yielded indices within these ranges, then the "substitute" gas was determined to be interchangeable. In addition, the performance of the substitute gas would be compared to the performance of the gases in the actual types of burners being used in the market area in order to verify its interchangeability. This work resulted in the AGA and Weaver indices, which may be used in combination with the Wobbe index. These parameters have not been actively utilized by most segments of the U.S. gas grid, as most gas markets in the United States have not faced interchangeability issues during the last 20 years.

Despite the fact that the above-mentioned interchangeability indices were developed more than 50 years ago, they may be equally applicable for today's burners. Manufacturers of many combustion appliances therefore base their fuel specifications on the Wobbe index, even for the most high tech appliances such as Dry Low NOx burners.

Although not well known, even the current ANSI standards for testing gas-fired furnaces use a Wobbe index for classifying the test gases, setting both a heating value of 1,075 Btu per cubic foot and a relative density of 0.65, which translates into a Wobbe index of 1,333 Btu per cubic foot.

Thus, a change of gas quality specification from a gross heating value to a Wobbe index would provide the end-user a more meaningful quality measure in line with the fuel specifications for gas appliances.

The change to a Wobbe index with a more flexible standards range would also significantly broaden supply options. The Wobbe index of even the richest LNG supplies could be adjusted to an acceptable level simply, if required, by the injection of a few percent of nitrogen. From a combustion perspective most LNG will then be fully interchangeable with pipeline gas; it will not produce more carbon monoxide or NOx emissions and will not cause flame lift or flashback as shown schematically in Figure E-3. This has recently

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2 Frank Johnson, David Rue, Colleen Sen (2002), *Gas Interchangeability Tests: Evaluating the Range of Interchangeability of Vaporized LNG and Natural Gas,* Gas Technology Institute Report, 2002.

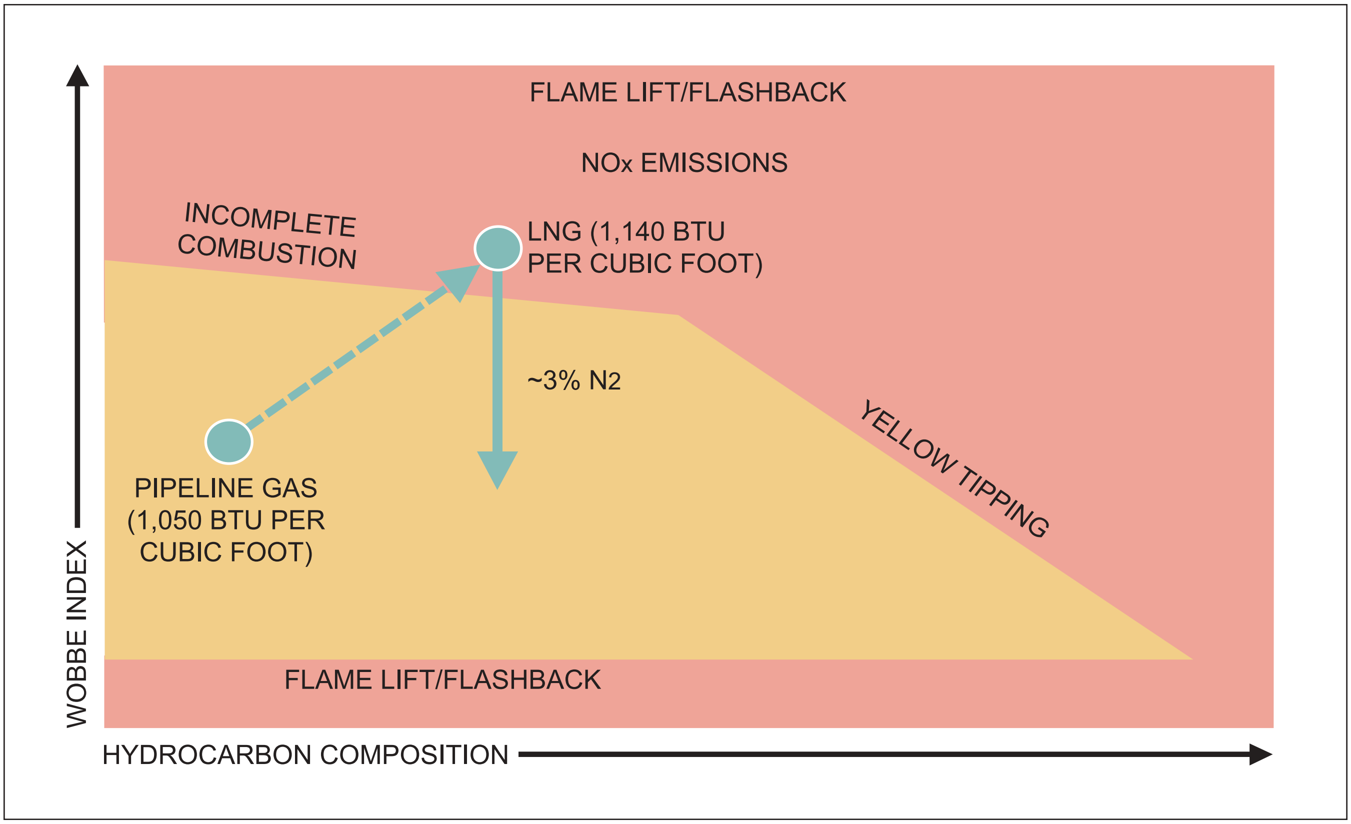

Figure E-3. Wobbe Index versus Hydrocarbon Composition

been reconfirmed in two interchangeability studies by Gas Technology Institute (GTI)[2] and TIAX. A few years ago a 1996 industry-wide U.S. Gas Quality Task Force also concluded that a limit on the Wobbe index would be much more meaningful than a limit on gross heating value.[3]

The same industry-wide Gas Quality Task Force also advised a change of the compositional limits on pentantes-plus (C5+) as currently used in some gas pipeline tariffs to a more meaningful Hydrocarbon Dew Point (HDP).[4] Some of the current C5+ limits may not provide proper protection against liquid formation. Despite its higher concentration of ethane, propane, and butanes, all LNG supplies will have a very low hydrocarbon dew point and will not cause any liquid formation downstream of the import terminal.

The Gas Quality Task Force did not pursue the advised changes, because there was no compelling need. That need has now emerged and the U.S. market should therefore reassess its current tariff specifications regarding gas quality in order to allow diversification of supplies as well as providing more meaningful quality guarantees for end-users.

A Wobbe index and a Hydrocarbon Dew Point do not address all gas quality issues. There are some end-users that have more specific requirements. Consumers that use natural gas as feedstock rather than fuel may require a specific compositional range. Any change of gas composition outside of that range can have an effect on the efficiency and capacity of such a plant even if the Wobbe index or the heating value stays constant. (The Wobbe index and heating value also do not cover the issue of knocking in gas engines that are tuned to burn lean pipeline gas.) The current quality specifications, however, also do not provide a proper guarantee to those end-users. As in most markets because those end-users make up only a small part of the overall demand, they need to be dealt with on an individual basis.

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3 R. W. Huffaker, "Results of the Grid Integration Project," Gas Quality Task Force, IGT Natural Gas and Energy Measurement Practices and Applications Conference 1996.

4 Ibid.

APPENDIX F

INFRASTRUCTURE
COST CALCULATION ASSUMPTIONS

General

- Output in 2002 dollars
- Nominal infrastructure costs escalate at 1.5% per year
- Inflation increases at 2.5% per year

Transmission Infrastructure

Infrastructure Cost = $1,100 per Capacity-Mile **x** Capacity-Miles **x** Cost Multipliers

Capacity-Miles = Capacity of Expansion **x** Miles in Pipeline Network Link[1]

Cost Multipliers = Regional Cost Multiplier **x** Pipe Diameter Multiplier **x** Type of Pipe Multiplier **x** Hot Market Multiplier

Cost Multiplier Assumptions

- Regional Cost Multiplier – Ranges 1.0 to 2.4 – More densely populated regions will have higher costs to construct gas pipelines.

New England	2.1
Northeast	2.1
Mid-Atlantic	2.1
South Atlantic	1.6
Florida	1.6
East South Central	1.9
Midwest	2.4
Upper Midwest	2.4
Central	1.8
West South Central	1.5
Southwest	1.5
Mountain	1.0
West North Central	1.8
Pacific Northwest	1.7
California	1.7
Gulf of Mexico Shelf	2.0
Gulf of Mexico Slope	2.0
Eastern Canada	1.6
Western Canada	1.1
Alaska	1.1

- Pipe Diameter Multiplier – Ranges from 1.0 to 3.0 – Smaller pipe has a higher cost per capacity-mile. Also large diameter pipe required for Alaska and Mackenzie Delta pipelines are expected to have higher cost standard pipe sizes.

Diameter Cost Multiplier

Design Flows (MMCF/D)	Minimum Flow (MMCF/D)	Diameter	Cost Multi-plier
67	1	2	3.0
139	100	16	2.5
245	200	20	1.9
389	350	24	1.5
1,084	900	36	1.0
Mega-Project	2,000	52	1.9

[1] Looping and Compression expansions require only 50% of miles associated with network link.

- Type of Pipe Multiplier – Default is 1.0 – Used for special factors (wall thickness) like in Alaska project where non-standard pipe is used in construction. Some frontier areas received a 1.2 multiplier.

- Hot Market Multiplier – Default 1.0 – Multiplier to be applied during periods of significant construction activity when material and or contractor availability may be affected.

Example Cost Calculation

Hypothetical 400 MMCF/D pipeline from Liedy Storage area to New Jersey in 2002

- Capacity-Miles = 400 MMCF/D x 410 miles over 2 model links = 164,000 Capacity-Miles

- Cost Multiplier = 2.1 (Northeast) x 1.5 (Diameter 24") x 1.0 (Type) x 1.0 (Hot) = 3.1 Cost Multiplier

- Cost = $1,100 x 164,000 x 3.1 = $568 million

- If built in 2010, nominal costs would be higher and adjusted to real dollars

- If this is looping and compression expansion, Capacity-Miles is 82,000 so cost would be estimated at $284 million

Compression Only Expansions

Infrastructure Cost = $1,350 per Horsepower of Compression x (230 HP per 1,000 Capacity-Miles) x Capacity-Miles

- Capacity-Miles are calculated in the same way as in the example above

- HP = 164,000 x 0.23 = 37,720 HP required

- Cost = 37,720 x $1350 = $51 million

Connection Pipe to Gas Production Facilities

Same format as transmission infrastructure with additional assumptions

- Number of new plant connections required based on the increased annual production at each network node. Average size of gas production facility is 390 MMCF/D. Number plants added = Production added/390.

- Each production facility needs approximately 50 miles of pipe to connect to pipeline network.

- Each plant adds 19,500 Capacity-Miles

- Regional cost multipliers same as above

- Diameter cost multiplier is 1.3 for pipe slightly bigger than 24"

- Cost of connecting new processing plant in Gulf of Mexico for example

- Cost = $1,100 x 19,500 x 2.6 = $56 million

Connection Pipe to Power Plants

Same format as transmission infrastructure with additional assumptions

- Number of new plant connections required based on the increased gas generation capacity at each network node. Average size of new power plant is 500 megawatts. Number plants added = Generation added/500.

- Each production facility needs approximately 15 miles of pipe to connect to pipeline network.

- Power generation lateral capacity at approximately 100 MMCF/D.

- Each plant adds 1,500 Capacity-Miles.

- Regional cost multipliers same as above.

- Diameter cost multiplier is 4 for small pipe.

- Cost of connecting a new gas fired generation plant in West South Central for example

  Capacity-Miles = 100 x 15 = 1,500

  Cost Multiplier = 1.5 (WSC) x 4 (Diameter) = 6.0

  Cost = $1,100 x 1,500 x 6.0 = $10 million per plant connection.

New Underground Storage Projects

- Storage projects estimated at costing $10 million per BCF of working gas capacity added.

- Cost of project includes up to 20 miles of connecting pipe of appropriate size.
- Cost estimated in real 2002 dollars with nominal infrastructure escalating at 1.5% per year and inflation at 2.5% per year.

Sustaining Infrastructure Costs

Assumes that sustaining infrastructure costs during ten years of mandatory testing will be significantly higher than has been historically observed.

- U.S. Pipelines will spend approximately $1.1 billion annually on replacing existing infrastructure. Cost expenditures are regionally proportional to existing pipe.
- Pipelines will replace 0.77 miles of transmission pipe for each $1 million spent in a region.
- Storage operators will spend about $120 million annually on sustaining costs.

TASK GROUP REPORTS

ACRONYMS AND ABBREVIATIONS

AEO	EIA's Annual Energy Outlook
AEUB	Alberta Energy and Utilities Board
AFUE	annual fuel utilization efficiency
AGA	American Gas Association
ANGTA	Alaska Natural Gas Transportation Act of 1976
ANGTS	Alaska Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
API	American Petroleum Institute
BACT	Best Available Control Technology
BCF	billion cubic feet
BCF/D	billion cubic feet per day
BLM	U.S. Bureau of Land Management
Btu	British thermal unit
CAPP	Canadian Association of Petroleum Producers
CC/CT	combined cycle/combustion turbine
CCGT	combined-cycle gas turbines
CEQ	Council on Environmental Quality
CERI	Canadian Energy Research Institute
CFE	Comision Federal de Electricidad (Mexico's Federal Electricity Commission
CFTC	Commodity Futures Trading Commission
CGPC	Canadian Gas Potential Committee
CHP	combined heat and power
CO2	carbon dioxide
COAs	conditions of approval
CRE	Comision Reguladora de Energia (Mexico's Energy Regulatory Commission)
CSS	cyclic steam stimulation
CZM	Coastal Zone Management
D&C	drilling and completion
DG	distributed generation
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
E&P	exploration and production
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency

EPCA	Energy Policy Conservation Act of 1975
ERCOT	Electric Reliability Council of Texas
EUR	estimated ultimate recovery
FCC	fluid catalytic cracking
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission (forerunner of FERC)
FTC	Federal Trade Commission
GDP	gross domestic product
GIIP	gas initially in place
GIP	gas in place
GMDFS	EEA's Gas Market Data and Forecasting System
GOM	Gulf of Mexico
GRI	Gas Research Institute
GSR	EEA's Gas Supply Review
GW	gigawatts
GWH	gigawatt hours
HCI	hydrocarbon indicator
HSM	EEA's Hydrocarbon Supply Model
HVAC	heating-ventilation-air conditioning systems
IECC	International Energy Conservation Code (superceded Model Energy Code in 1998)
IHS	IHS Energy Group
INGAA	Interstate Natural Gas Association of America
IP	industrial production
IP	initial production rate
ISTUM-2	Industrial Sector Technology Use Model
JAS	API's Joint Association Survey
KW	kilowatts
KWH	kilowatt hours
LDC	local distribution company
LIHEAP	Low Income Home Energy Assistance Program
LNG	liquefied natural gas
LSE	load serving entity
MACT	Maximum Achievable Control Technology
MCF	thousand cubic feet
MECS	EIA's Manufacturing Energy Consumption Survey
MEPS	Minimum Energy Performance Standards
MM	million
MMBtu	million British thermal units
MMCF	million cubic feet
MMCF/D	million cubic feet per day
MMS	Minerals Management Service
MOU	memorandum of understanding
MSC	Multiple Services Contract
MTA	million tons per annum
MTBE	methyl tertiary butyl ether
MW	megawatts
MWH	megawatt hours
NAECA	National Appliance Energy Conservation Act of 1987 and amendments of 1988
NAICS	North American Industry Classification System
NEB	National Energy Board of Canada

NECPA	National Energy Conservation Policy Act of 1978
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NGL	natural gas liquid
NGPA	National Gas Policy Act of 1978
NGV	natural gas vehicle
NOx	nitrogen oxides
NOAA	National Oceanic and Atmospheric Administration
NPC	National Petroleum Council
NPRA	National Petrochemical & Refiners Association
NPRA	National Petroleum Reserve, Alaska
NSR	EPA's New Source Review
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
O&M	operation and maintenance
Pemex	Petroleos Mexicanos
PIFUA	Powerplant and Industrial Fuel Use Act of 1978
POLR	provider of last resort
PSA	EIA's Petroleum Supply Annual
PSAC	Petroleum Services Association of Canada
psi	pounds per square inch
PUC	public utility commission
PURPA	Public Utility Regulatory Policies Act of 1978
quads	quadrillion Btu
RACC	refiner acquisition cost of crude oil
R&D	research and development
REC	Renewable Energy Credit (or Certificate)
RFG	reformulated gasoline
ROE	return on equity
R/P	reserves to production (ratio)
RTOs	Regional Transmission Organizations
RPS	Renewable Portfolio Standards
SAGD	steam-assisted gravity drainage
SEDS	EIA's State Energy Data System
SENER	Secretaria de Energia (Mexico's Energy Ministry)
SIC	Standard Industrial Classification
SIP	state implementation plan
SOLR	supplier of last resort
SOx	sulfur oxides
SO2	sulfur dioxide
TAPS	Trans-Alaska Pipeline System
TCF	trillion cubic feet
TRC	tradable renewable certificates
TW	terawatts
TWH	terawatt hours
USGS	United States Geological Service
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate crude oil

VOLUME V

GLOSSARY

Access
The ability to drill and develop oil and natural gas resources, build associated production facilities, and construct transmission and distribution facilities on either public and/or private land.

Basis
The difference in price for natural gas at two different geographical locations reported for the same time period.

British Thermal Unit (Btu)
A Btu is the amount of heat required to change the temperature of one pound of water one degree Fahrenheit, and is the common energy measurement for natural gas. One cubic foot of natural gas contains approximately 1,000 Btu.

Burnertip
The point at which natural gas is used as a fuel.

Capacity, Peaking
The capacity of facilities or equipment normally used to supply incremental gas or electricity under extreme demand conditions. Pipeline peaking capacity is generally available for a limited number of days at maximum flow rate while electric peaking capacity is generally available whenever market price conditions cover all variable costs and startup expenses for such capacity.

Capacity, Pipeline
The maximum physical 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 contract service conditions.

Citygate
The point at which interstate and intrastate pipelines sell and deliver natural gas to local distribution companies.

Cogeneration
The production of electricity and useful thermal energy from the same initial energy source. Natural gas is a favored fuel for combined-cycle cogeneration units, where it directly produces electricity from a combustion turbine and the resultant waste heat is converted to steam for process use and for generating electricity in a heat steam recovery generator (HSRG).

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.

Compressed Natural Gas (CNG)
Natural gas cooled to a temperature below 32°F and compressed to a pressure ranging from 1,000 to 3,000 pounds per square inch in order to allow the transportation of large quantities of natural gas.

Cost Recovery
The recovery of permitted costs, plus an acceptable rate of return, for an energy infrastructure project subject to rate regulations.

Cryogenic
Refers to low temperature and to low temperature technology. There is no precise temperature for an upper boundary, but –100°F is often used.

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 standard conditions of temperature, pressure, and water vapor.

Dekatherm (Dth)
A unit of heating value equal to ten therms or one million Btu. Very roughly, 1 MCF = 1 MMBtu = 1 Dth.

Deliverability
The volume that a particular well, storage field, pipeline, or distribution system can supply during a 24-hour period.

Distribution Line
Natural gas pipeline system, typically operated by an LDC (local distribution company), for the delivery of natural gas to end-users.

Elasticity
An economic metric that typically measures the magnitude of changes in supply or demand as a function of changes in price.

Electric
A sector of customers or service defined as generation, transmission, distribution, or sale of electric energy.

End-User
An entity that actually consumes energy, as opposed to one who sells or re-sells it.

Fahrenheit degrees (F)
A temperature scale according to which water boils at 212 and freezes at 32 degrees. Convert to Centigrade degrees (C) by the following formula: (F-32)/1.8= C.

Federal Energy Regulatory Commission (FERC)
The federal agency that regulates rates and terms of service for interstate gas pipelines and interstate gas sales and for wholesale electric power transactions under federal energy statutes. It also regulates onshore LNG facilities.

Feedstock
The use of one product as an ingredient to produce another, such as using natural gas as a feedstock to produce ammonia or methanol.

Firm Customer
A customer who has contracted for firm service.

Firm Service
Service offered to customers under schedules or contracts that anticipate no interruptions, except for force majeure.

Flaring
Burning natural gas at the field site because it cannot be sold. It is illegal in many countries.

Fuel Switching
Substituting one fuel for another based on price and availability. Large industries and power generators 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.

Gigawatts
One billion watts, or one thousand megawatts.

Gross Domestic Product (GDP)
A dollar measure of total output of goods and services in the nation. Note that GDP can be measured in nominal or current dollars or in real dollars, which removes the effects of inflation.

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.

Impoundment
Spill control for tank content designed to limit the liquid travel in case of release. May also refer to spill control for LNG piping or transfer operations.

Industrial
A sector of customers or service defined as manufacturing, construction, mining, agriculture, fishing, and forestry.

Kilowatt
One thousand watts.

Liquefied Natural Gas (LNG)
The liquid form of natural gas, which has been cooled to a temperature –256°F or –161°C and is maintained at atmospheric pressure. This liquefaction process reduces the volume of the gas by approximately 600 times its original size.

LNG tankers
Ships that are double hulled, especially designed with the LNG being stored in special containment systems slightly above atmospheric pressure and at –256°F. These vessels are designed to protect the cargo tanks and to prevent leakage or rupture in an accident.

Load Profiles

Gas or electric power usage over a specific period of time, usually displayed as a graphical plot.

Local Distribution Company (LDC)

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. An LDC typically operates as a regulated utility within a specified franchise area.

Megawatts

One million watts or one thousand kilowatts.

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.

Natural Gas Liquids (NGLs)

Natural gas liquids (ethane, propane, butane, etc.) are mixtures of light hydrocarbons that are gaseous at reservoir temperatures and pressures, but are recovered as liquids through condensation or absorption.

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 are untested by actual drilling.

NIMBY (Not In My Back Yard)

An acronym that represents opposition to any new energy facility.

Nominal Dollars

Dollars that have not been adjusted for inflation.

Nonconventional Gas

Natural gas produced from coalbeds, shales, and low permeability reservoirs. Development of these reservoirs can require different technologies than conventional reservoirs.

Peak-Day Demand

The maximum daily quantity of gas or power used during a specified 24-hour period and evaluated over a specific period such as a year.

Peak Shaving

Methods to reduce the peak demand for gas or electricity or to meet those peaks with alternate delivery sources or methods. Examples would be price-controlled interruptions for demand reduction or propane-air and distributed LNG for alternate resources.

Peakshaving LNG Facility

A facility for both storing and vaporizing LNG, intended to operate on an intermittent basis to meet relatively short-term peak gas demands. A peakshaving plant may also have liquefaction capacity, which is usually quite small compared to vaporization capacity at such facility.

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.

Refiner Acquisition Cost of Crude Oil (RACC)

The cost of crude oil, including transportation and other fees paid by the refiner. The composite cost is the weighted average of domestic and imported crude oil costs. Note: The refiner acquisition cost does not include the cost of crude oil purchased for the Strategic Petroleum Reserve (SPR).

Refrigeration Process

The way natural gas is liquefied, which reduces the volume of the gas by approximately 600 times its original size. This process enables LNG to be transported globally in specially designed ocean vessels.

Regasification

The process through which LNG transfers from liquid to gas. It is usually done at a facility called a receiving terminal equipped with vaporizers, docks, and storage tanks.

Regional Transmission Organization (RTO)

A regulatory-recognized organization of electric 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 households that consume energy primarily for space heating, water heating, air conditioning, lightning, refrigeration, cooking, and clothes drying.

Revenue
The total amount of 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.

Spot Market
Deals or contracts covering cargoes for less than one year.

Storage Facilities
Facilities used to store natural gas that has been transferred from its original location. Usually consists of natural geological reservoirs like depleted oil or gas fields or underground salt domes. Also refers to tanks used to store LNG.

Stranded Gas
Gas is considered stranded when it is not near its customer and a pipeline is not economically justified.

Terawatts
One trillion watts.

Tonnes
Tonnes, or Metric Ton, is a measurement used in LNG shipments and is approximately 2.47 cubic meters of LNG.

Watt
The common U.S. measure of electrical power.