Findings

FINDING 1: THERE HAS BEEN A FUNDAMENTAL SHIFT IN THE NATURAL GAS SUPPLY/DEMAND BALANCE THAT HAS RESULTED IN HIGHER PRICES AND VOLATILITY IN RECENT YEARS. THIS SITUATION IS EXPECTED TO CONTINUE, BUT CAN BE MODERATED.

During the 1990s, environmental standards and economic growth were the forces driving the demand for natural gas in North America. Historically, in North America drilling activity has responded quickly to market signals and, together with increasing supplies from Canada, has yielded sufficient production to meet demand. Figure 9 shows U.S. and Canadian production. It now appears, however, that natural gas productive capacity from accessible basins in the United States and Western Canada has reached a plateau. Recent experience shows steeper decline rates in existing production and a lower average production response to higher prices from new wells in these areas. This trend is expected to continue. As a result, markets for natural gas have tightened to a degree not seen in recent experience and prices have increased well above historical levels. These higher prices have been accompanied by significant price volatility, as illustrated in Figure 10.

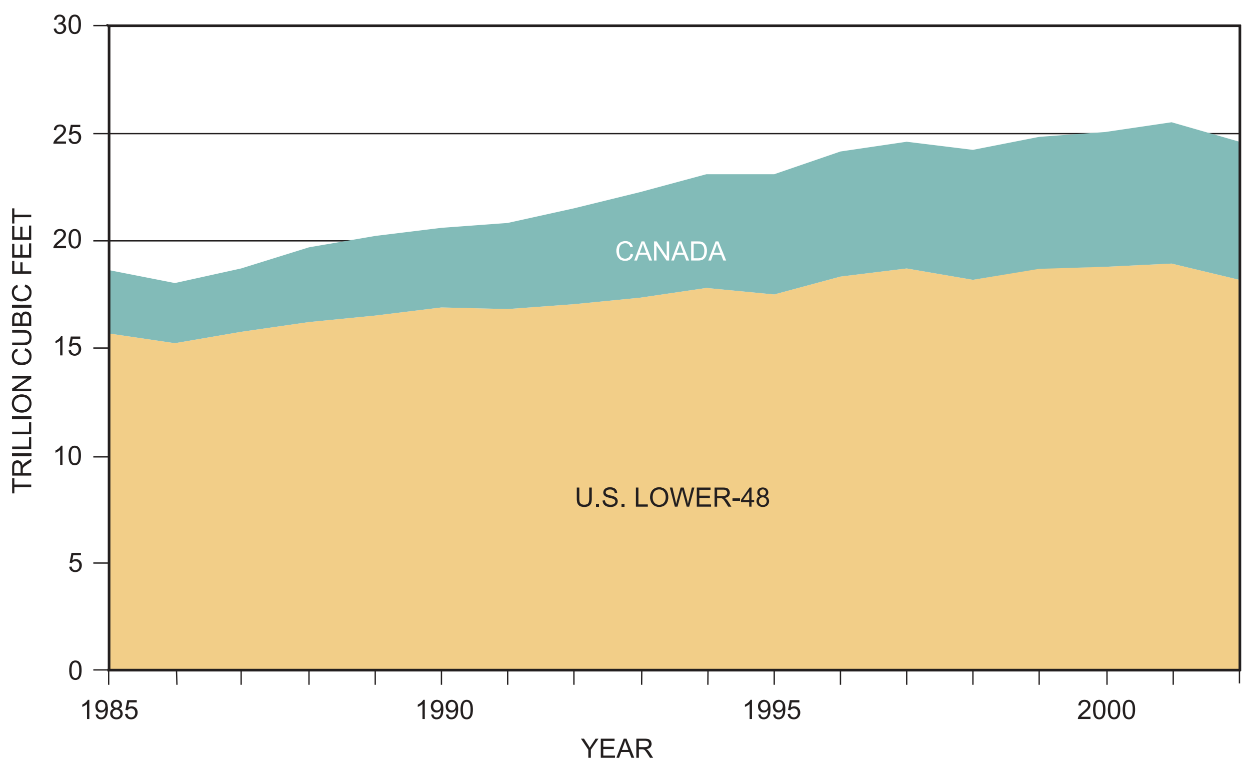
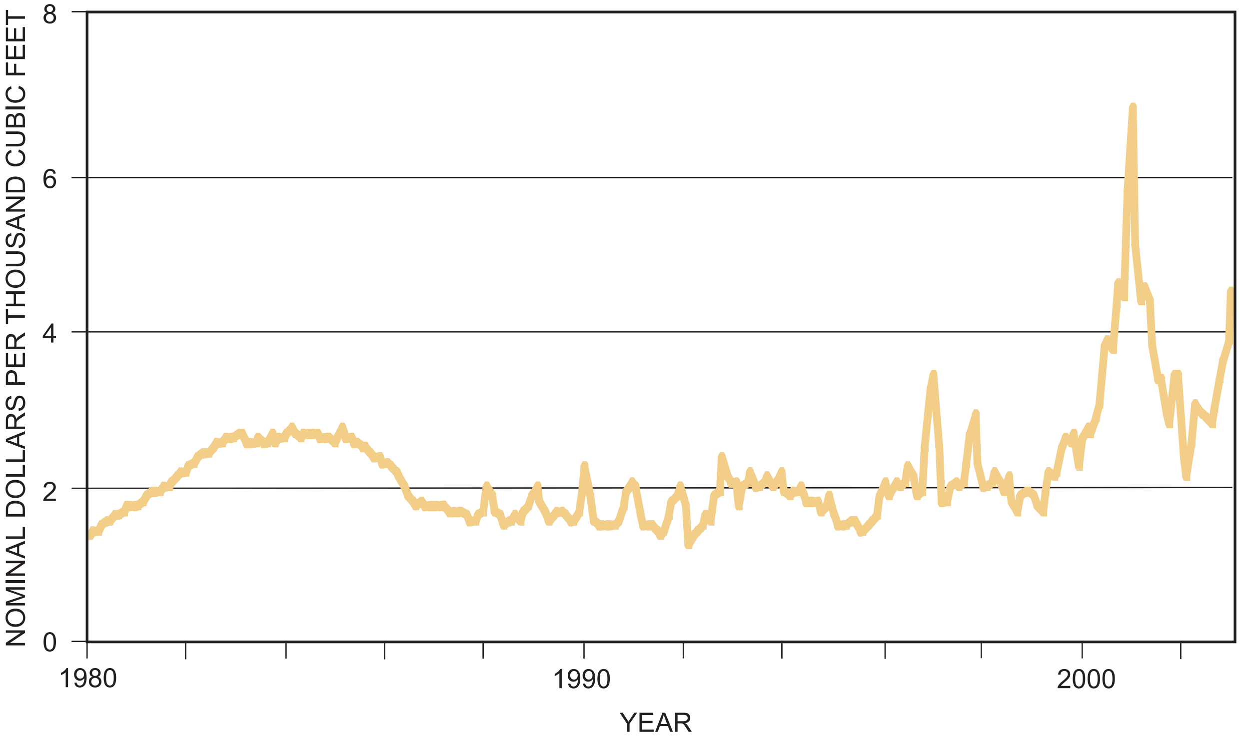


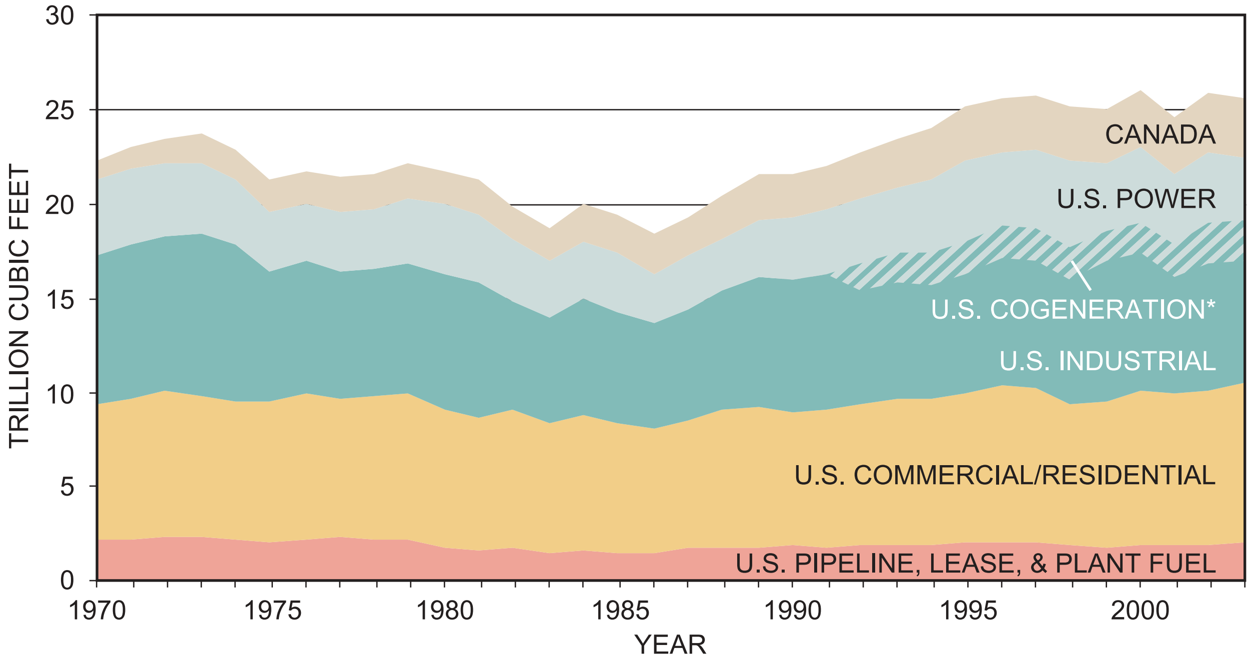
FIGURE 9
U.S. LOWER-48 AND CANADIAN NATURAL GAS PRODUCTION



Source: Energy Information Administration.

FIGURE 10
U.S. WELLHEAD GAS PRICE

Natural gas demand grew by more than 40% between 1986 and 1997, from 16 TCF/year to 23 TCF/year, as illustrated in Figure 11. While overall demand has persisted between 22 TCF/year and 23 TCF/year since 1997, the market has fundamentally changed. Natural gas used for power generation has grown while industrial use has declined. Today, it is productive capacity, including established import capacity, that drives the tight supply/demand balance; the resulting higher prices are limiting the ability of natural gas demand to grow.



* Energy Information Administration reports cogeneration beginning 1989.

FIGURE 11
U.S. AND CANADIAN NATURAL GAS DEMAND

This is in contrast to the "gas bubble" environment of the late 1980s and 1990s that was characterized by a surplus of supply and weak demand. This "bubble" kept prices low and dampened price volatility. This market was influenced by a succession of since-modified legislative and regulatory decisions beginning with the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA) and the Natural Gas Policy Act of 1978 (NGPA). While the PIFUA placed restrictions on industrial and power generation uses of natural gas, the NGPA set in motion a process that encouraged gas supply growth. Amendments in 1987 to the PIFUA removed restrictions on the use of gas in power generation, and the Natural Gas Wellhead Decontrol Act of 1990 removed wellhead price controls.

Thus, a responsive market developed in the early 1990s for the supply and trade of natural gas. This market grew out of deregulation of supply and demand, and was reinforced by a series of FERC Orders creating an unbundled and more flexible transportation system. The excess productive capacity of North America, combined with storage capability for meeting seasonal demand surges meant that there was sufficient supply to meet daily, seasonal, and annual gas requirements, including those driven by weather and/or economic growth.

The capability to consume natural gas continues to increase. The number of residential natural gas customers grew from 48 million in 1987 to 60 million in 2001.[3] Of the 220,000 megawatts of new powerplant capacity recently constructed or about to be placed in operation

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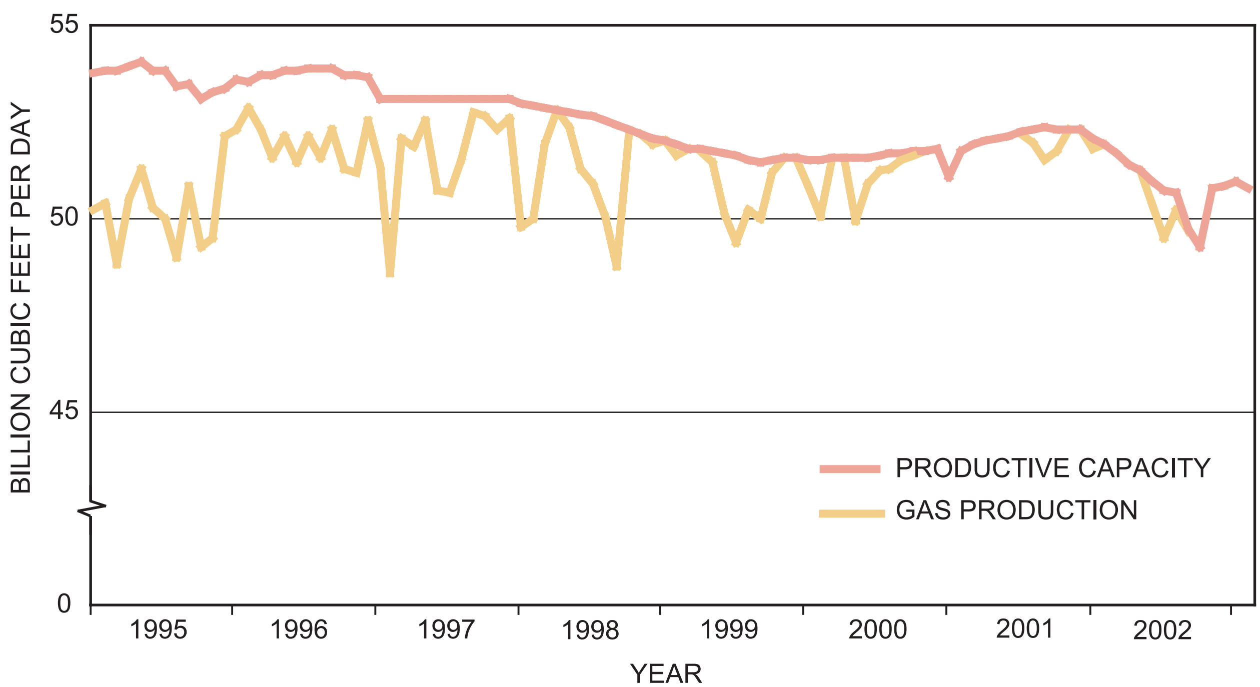
[3] U.S. Energy Information Administration.

over the next few years, well over 90% are fueled with natural gas.[4] Industrial consumption, including cogeneration applications, grew by almost 48% from 1986 to 2001.

The combination of growing demand and limited supply has resulted in a disappearance of the "gas bubble," as shown in Figure 12. It has created an overall tightening of the market and led in recent years to higher gas prices and price volatility. The market is less able to absorb changes in supply or demand without a significant swing in price. This dynamic will continue until additional supplies are brought to market and more demand flexibility is achieved.



Source: Energy and Environmental Analysis, Inc.

FIGURE 12
LOWER-48 DRY GAS PRODUCTION VS. DRY GAS PRODUCTIVE CAPACITY

[4] Daniel Yergin Speech before the Natural Gas Summit in Washington, DC, June 26, 2003.

FINDING 2: GREATER ENERGY EFFICIENCY AND CONSERVATION ARE VITAL NEAR-TERM AND LONG-TERM MECHANISMS FOR MODERATING PRICE LEVELS AND REDUCING VOLATILITY.

Improved efficiency of energy use has been a major feature of the U.S. economy since the 1970s. For the past 30 years, the amount of gas used in the production of a dollar's worth of economic output has continued to decrease. Since 1974, the industrial sector alone has reduced its energy use for fuel and power consumption per unit of output by nearly 40%. Residential consumers reduced natural gas use per customer by 16% from 1980 to 2001, primarily as a result of more-efficient space heating and improved housing characteristics.[5] The power generation industry has also achieved significant efficiency gains through the introduction of highly efficient combustion turbines, combined heat and power configurations, and combined cycle applications. Between 1997 and 2001, the net effect of these innovations has been a 15% increase in efficiency of gas consumed to produce power.

Continued energy conservation and more efficient use of existing equipment can ease short-term market pressures. Natural gas conservation and efficiency measures in residences and commercial establishments – which collectively represent over 40% of total U.S. demand – can contribute substantially to higher efficiencies. For example, electricity conservation can reduce the demand on regional power systems, minimizing the operation of "peaking" capacity that is often supplied by gas-fired facilities. Electric power generators can also reduce natural gas demand by ensuring higher utilization of combined-cycle units instead of less-efficient gas-fired boilers.

The economy has generally become more efficient in its use of natural gas and other energy sources, even during periods of low prices, due to technological innovation, the ongoing shift to less energy-intensive industries, and government policies. Figures 13, 14, and 15 illustrate efficiency gains in natural gas utilization for the industrial, electric power, and residential and commercial sectors, respectively. These historical gains will generally be sustained due to historical and future changes in capital stock, and as new construction incorporates more-efficient building codes and standards. These continuing improvements in the efficiency of electricity and natural gas consumption are assumed in both the Reactive Path and Balanced Future scenarios, and are illustrated for the Balanced Future scenario in Figure 16. The increased residential and commercial energy efficiencies in the Balanced Future scenario are be assumed to be the result of market mechanisms that provide clear natural gas and power price signals to consumers, by consumer education, and by appropriate changes to building standards.

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[5] American Gas Association, Energy Analysis EA 2003-01, June 16, 2003.

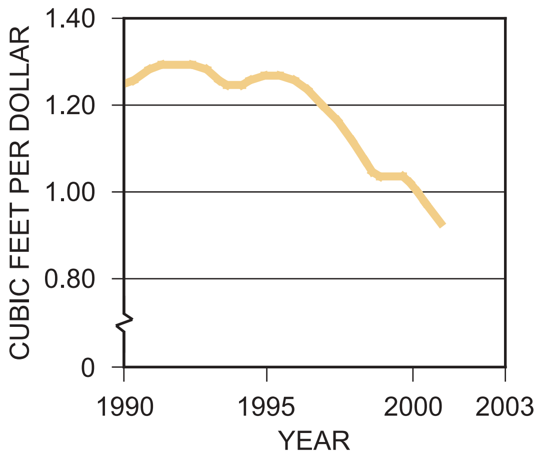


FIGURE 13
AVERAGE INDUSTRIAL GAS INTENSITY
(CUBIC FEET OF GAS CONSUMED
PER DOLLAR OF INDUSTRIAL OUTPUT)

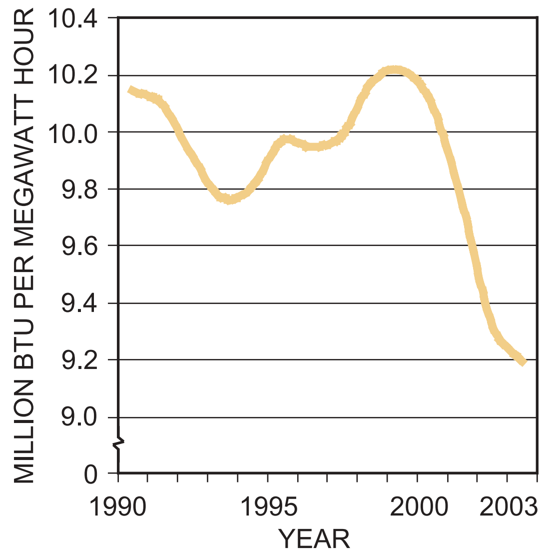


FIGURE 14
GAS-FIRED GENERATION HEAT RATE

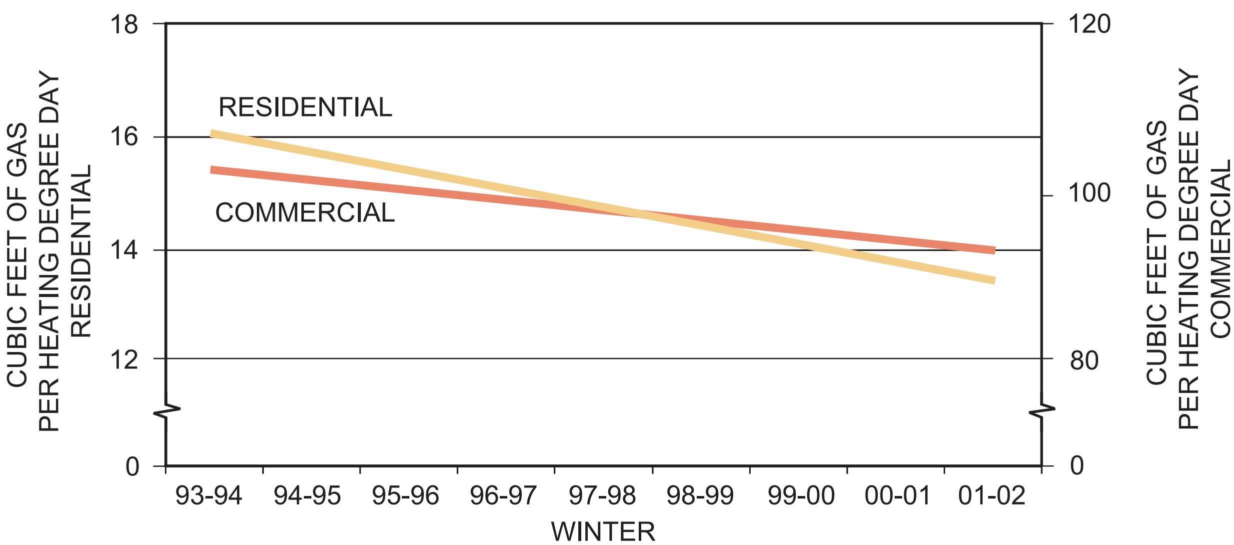
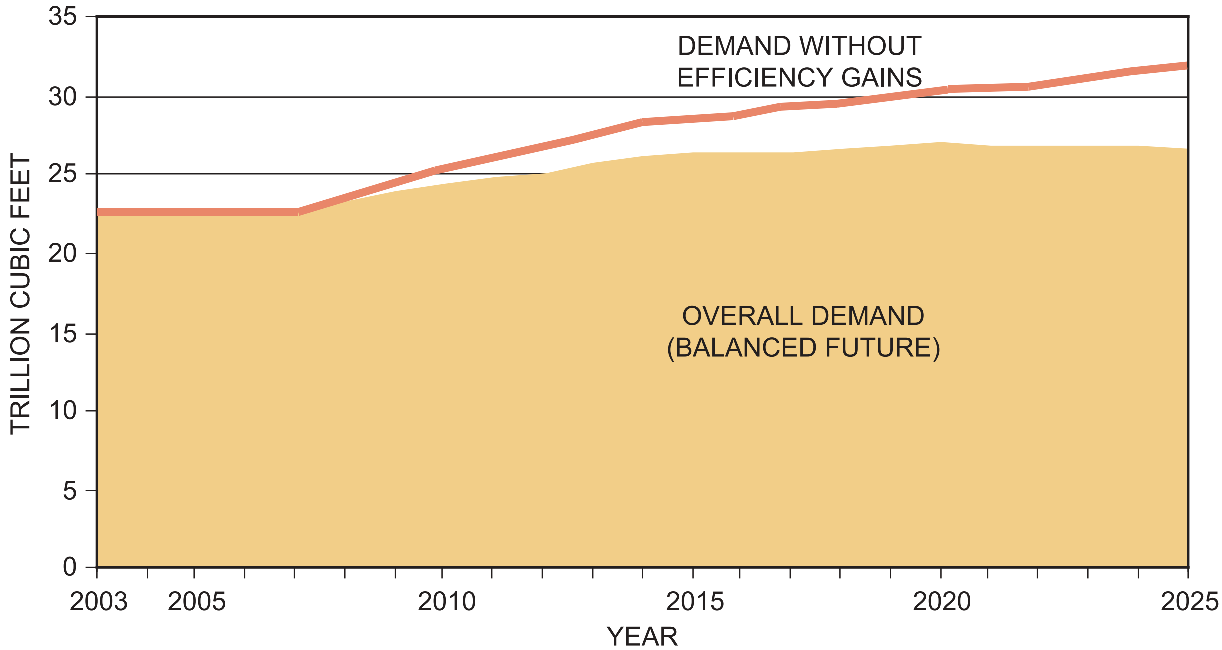


FIGURE 15
RESIDENTIAL AND COMMERCIAL GAS USE INTENSITY



* Energy efficiency gains in NPC modeling of future gas demand are principally from: decreased electric power demand intensity; increased efficiency in gas-fired power generation, industrial boilers, and industrial process heat; and efficiency gains in commercial and residential gas consumption.

FIGURE 16
ENERGY EFFICIENCY EFFECT ON GAS CONSUMPTION*

FINDING 3: POWER GENERATORS AND INDUSTRIAL CONSUMERS ARE MORE DEPENDENT ON GAS-FIRED EQUIPMENT AND LESS ABLE TO RESPOND TO HIGHER GAS PRICES BY UTILIZING ALTERNATE SOURCES OF ENERGY.

For the past 15 years, industrial consumers and power generators have become increasingly dependent on natural gas-based technologies for meeting their energy requirements and for satisfying more-stringent air quality standards. These consumers have chosen gas-fired equipment based on the following factors:

- **Life-cycle economics.** Gas-fired applications generally have lower capital costs. Gas-fired combustion turbines used in power generation and industrial cogeneration require shorter construction lead times and are available in convenient modular designs. This saving in capital costs was especially attractive in the late 1980s and 1990s when gas prices were consistently below the equivalent liquid fuel prices.

- **Environmental performance.** Improved air emissions performance of natural gas-based technologies has favored investments in facilities that use natural gas. In many instances, power generators and industrial consumers made investment decisions favoring natural gas in order to achieve compliance with “New Source Performance Standards” and/or as a condition of a “New Source Review” proceeding.

- **Land use**. Gas applications generally require less land and are less intrusive than other fossil fuel applications. Modular gas-fired generation facilities have been used to meet increased electric power demand frequently as an alternative to extending power transmission lines to certain areas.

As shown in Figure 17, natural gas demand for power generation (including industrial-based generation) grew by more than 50% in the 15 years ending in 2002. Despite recent declines in demand from the industrial sector – particularly portions of the chemical industry and metals manufacturers – overall industrial gas demand is greater today than 15 years ago.

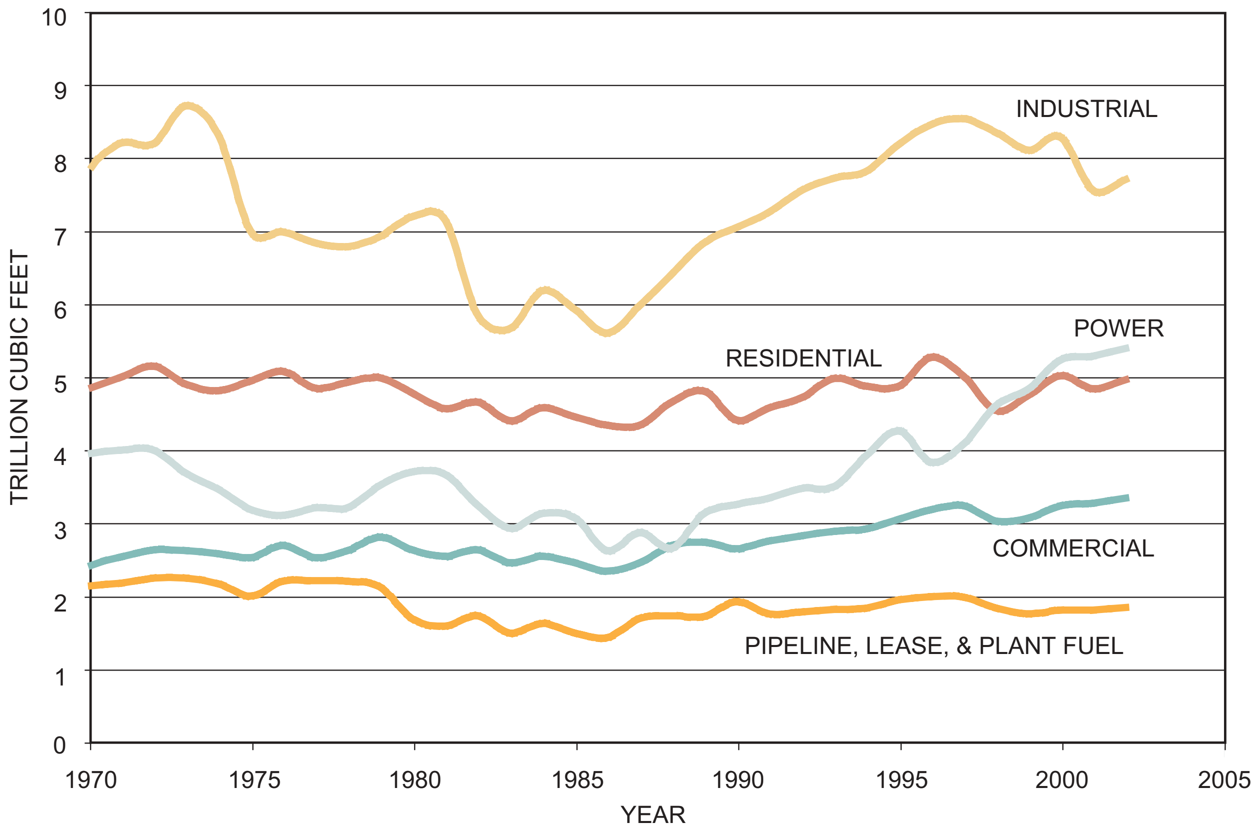


FIGURE 17
NATURAL GAS CONSUMED BY SECTOR

At the same time, the stock of gas-fired power generation and industrial equipment became less flexible in its ability to operate with alternate fuels. This loss of flexibility has been driven in part by an array of governmental policies such as local siting restrictions on fuel backup and New Source Review proceedings. World economic and competitive forces provided the incentive for energy consumers to seek industrial process efficiencies and control costs. For example, existing burners are "tuned" to maximize operational and environmental efficiency when operating solely with natural gas. Power generators and industrial gas users have retired or mothballed boilers and other equipment capable of using dual fuels, such as oil and gas. In addition, not using oil or coal in current or retiring processes yielded the emission credits that were needed for plant expansions or new process construction. Some plant sites, once capable of using dual fuels now lack the permits to burn fuels other than natural gas and/or lack both the infrastructure and the physical storage capacity for using alternative fuels.

Figure 18 approximates the current short-term flexibility of U.S. power generation and industrial capacity for responding to changes in natural gas prices, as considered in NPC modeling. This indicates that about 6 billion cubic feet per day (BCF/D) of fuel-switching or demand suppression would be expected to occur at prices up to $6.50/MMBtu, and up to 10 BCF/D at prices of $8.00/MMBtu.

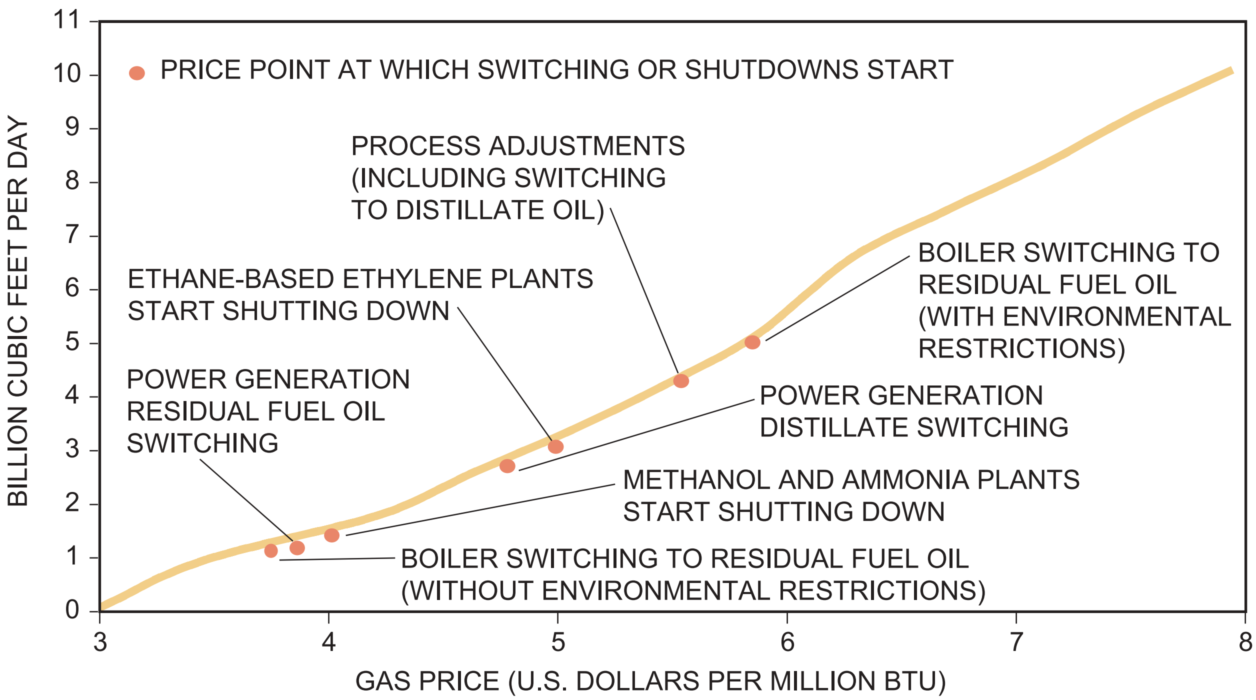


FIGURE 18
INDUSTRIAL AND POWER GENERATION
NATURAL GAS FLEXIBILITY, JULY 2003

Through at least 2008, natural gas-based technologies will represent about one-third of U.S. generation capacity. Subject to significant variation due to the weather, natural gas should supply between 15% and 20% of the electricity generated during this time. In contrast, oil/gas boiler generation capacity is about 12% of total U.S. capacity, and will provide about 2% of the electricity generated. Figure 19 shows the relative shares of oil and gas used in power generation.

Boiler fuel for steam generation represents 25%-30% of industrial gas consumption. An industry-wide survey by the Department of Commerce for the period 1994-1998, suggested that up to 28% of industrial boilers at the end of that period were fuel-switchable. However, one finding of the workshops conducted by the Demand Task Group and the many gas-intensive industrial users was that the practical level of boiler fuel-switching capability is much lower today; only approximately 10% of the total – or approximately 200 BCF/year; some industrial consumers reported it to be as low as 5%.

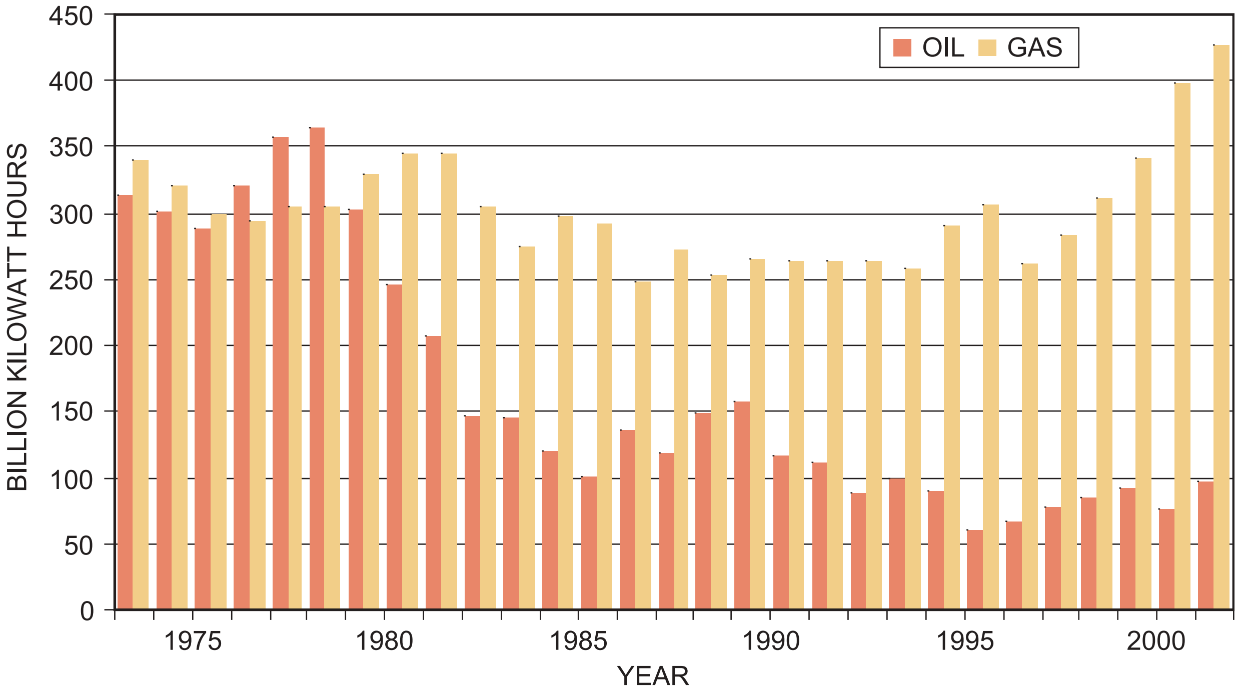


FIGURE 19
U.S. ELECTRICITY GENERATED, BY OIL AND GAS

FINDING 4: GAS CONSUMPTION WILL GROW, BUT SUCH GROWTH WILL BE MODERATED AS THE MOST PRICE-SENSITIVE INDUSTRIES BECOME LESS COMPETITIVE, CAUSING SOME INDUSTRIES AND ASSOCIATED JOBS TO RELOCATEOUTSIDE NORTH AMERICA.

Long-term natural gas demand is expected to increase due to economic growth and increased environmental regulations, fundamental changes in energy usage patterns and in investments in gas-intensive equipment. Influenced heavily by short-term weather cycles, these increases will be driven by changing demographic patterns, and by actions taken by power generators and industrial consumers to comply with increasing air quality standards. This growth will be slowed by higher prices that will principally affect energy-intensive consumers in the industrial sector – chemicals, refining, and metals – that, unlike power generators, generally compete in world markets.

Future U.S. and Canadian natural gas demand is reflected in Figure 20 for the Reactive Path case. This figure shows an overall increase of about 23% by 2025 from 2002. The Reactive Path and the Balanced Future cases both assume average annual U.S. GDP growth from 2005-2025 of 3%, and annual Canadian GDP growth of 2.6%, based on historical averages. The cases also assume weather conditions at the average of the past 30 years. Each case assumes future air regulations will conform to current law; but the cases differ in their expectations for coal plant shutdowns due to mercury emission rules. The Balanced Future assumes deliberate introduction of fuel flexibility in power generation and industrial applications, as well as increased energy efficiency in the commercial and residential sector. Demand in the Balanced Future is not greatly different to that of the Reactive Path, because the offsetting effects of greater energy efficiency and greater use of alternate fuels assumed in the Balanced Future would tend to reduce demand, but would be offset by the effects of lower prices, which tend to increase demand.

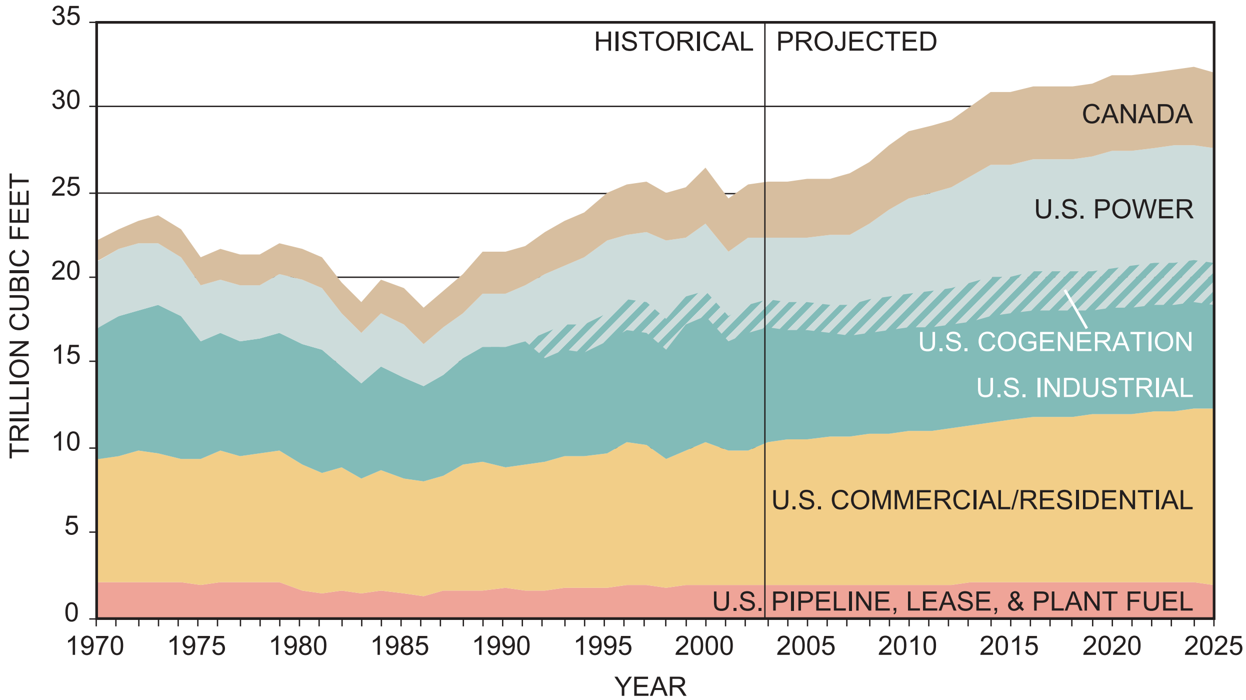


FIGURE 20
HISTORICAL GAS DEMAND AND "REACTIVE PATH" PROJECTION

Power Generation

U.S. electricity demand grew 31% from 1990 to 2002, and the increase in U.S. gas supply directed to power generation increased from 22% to 30%. The rapid buildup of gas-based generation capacity starting in the 1990s reflects investment efficiencies, environmental performance, operational flexibility, siting ease, and production costs for these facilities. The outlook for natural gas in power generation is defined by the following factors.

- **Electricity demand**. Electricity demand has steadily grown in relation to GDP growth, and the NPC expects this growth to continue. U.S. electricity demand has grown an average of 2.5%/year since 1973. In the Reactive Path scenario, electricity demand is assumed to grow an average of 1.9%/year through 2025, while in the Balanced Future scenario growth of 1.7%/year is assumed. Although each scenario assumes similar GDP growth as in the past three decades, power demand growth is forecast to be lower, reflecting greater energy efficiency.

- **Power generation capacity**. The scenarios assume: (a) in the Reactive Path scenario, retirement or mothballing of 18 gigawatts (GW) of oil- and gas-fired steam boiler units through 2010, and retirement of 21 GW of smaller coal-fired units in 2007-2009 due to the Maximum Achievable Control Technology (MACT) standards for mercury; (b) lower levels of oil/gas and coal retirements in the Balanced Future scenario; (c) continued exclusion of new coal-based technology from the U.S. west coast and from ozone non-attainment areas of the U.S. east coast; (d) continued development of renewable technology, reflecting a combination of tax incentives and efficiency increases over time, with 73 GW constructed through 2025 in the Reactive Path scenario, and 155 GW in the Balanced Future scenario; (e) competitive coal-based technology – using all required environmental controls – with over 100 GW of capacity likely to be constructed, primarily after 2015; (f) continued operation of existing nuclear capacity through at least 2025, but no new nuclear capacity due to overall costs and perceived investment risks associated with waste disposal; and (g) some increase in hydroelectric generation in Canada, none in the United States.

Figure 21 shows future U.S. generation capacity, by fuel source, as projected in the Reactive Path scenario. Figure 22 illustrates the quantities of electricity generated by fuel type. Because short-term weather cycles will have a significant effect on electric power demand, the NPC also conducted sensitivity analyses, which indicated that these cycles could markedly change natural gas requirements for power generation in any given year.

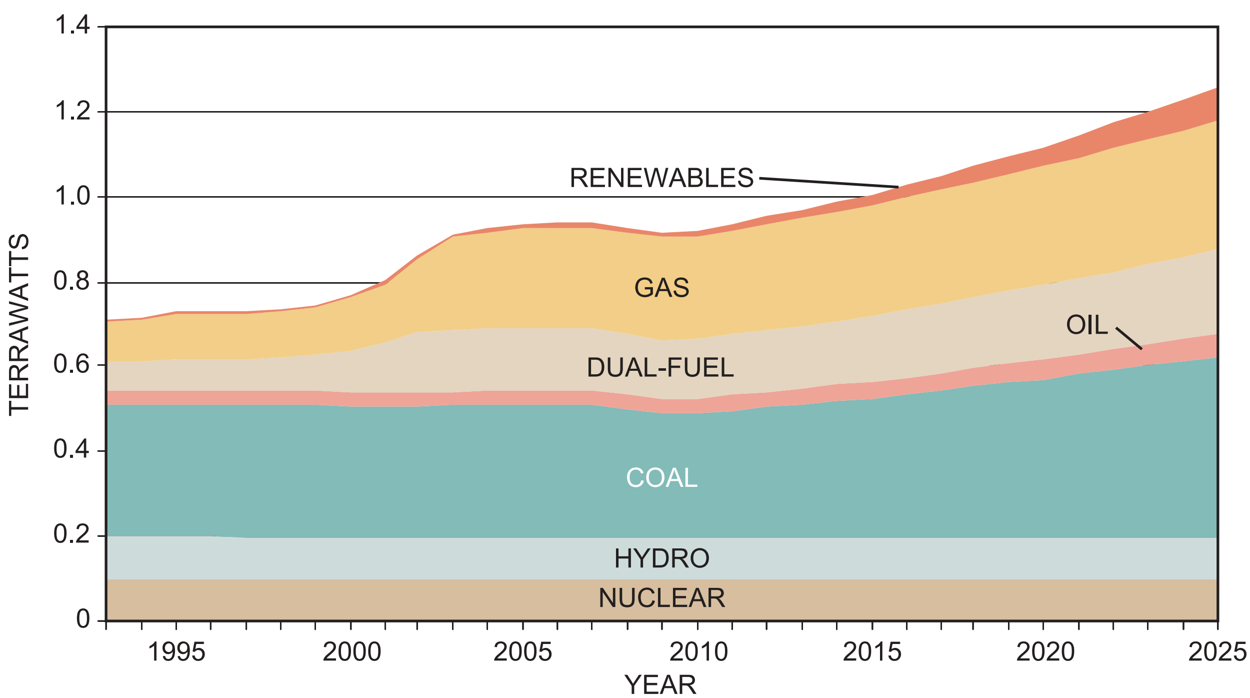


FIGURE 21
ELECTRIC POWER GENERATION CAPACITY BY FUEL TYPE

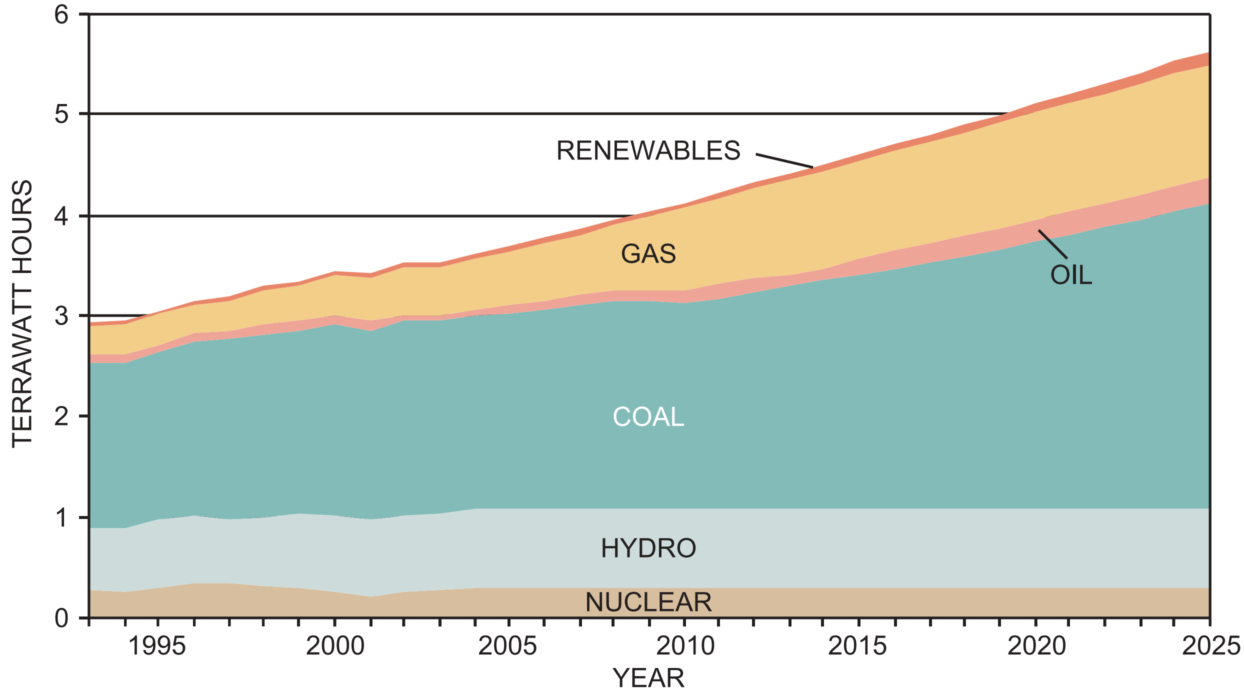


FIGURE 22
ELECTRICITY GENERATED BY FUEL TYPE

Industrial Use

U.S. industries derive 40% of their primary energy from natural gas. Natural gas and/or the ethane produced in association with natural gas are the key raw materials in the manufacture of ammonia, methanol, ethylene, and the hydrogen that is produced outside of petroleum refining processes. Natural gas usage was analyzed for key categories of industrial consumers – chemicals, refining, primary metals, paper, stone/clay/glass, food/ beverage, and other industries.

The potential demand for natural gas by industrial consumers in a Reactive Path scenario is illustrated in Figure 23; Figure 24 shows gas use by principal industrial application. In this case, industrial demand would be most affected in the near-term, as higher natural gas prices increase the pressure on gas-intensive industrial consumers to discontinue some operations and limit investments in North American chemical process capacity. Manufacturers of ammonia, methanol, petrochemicals, and metals would be most affected.

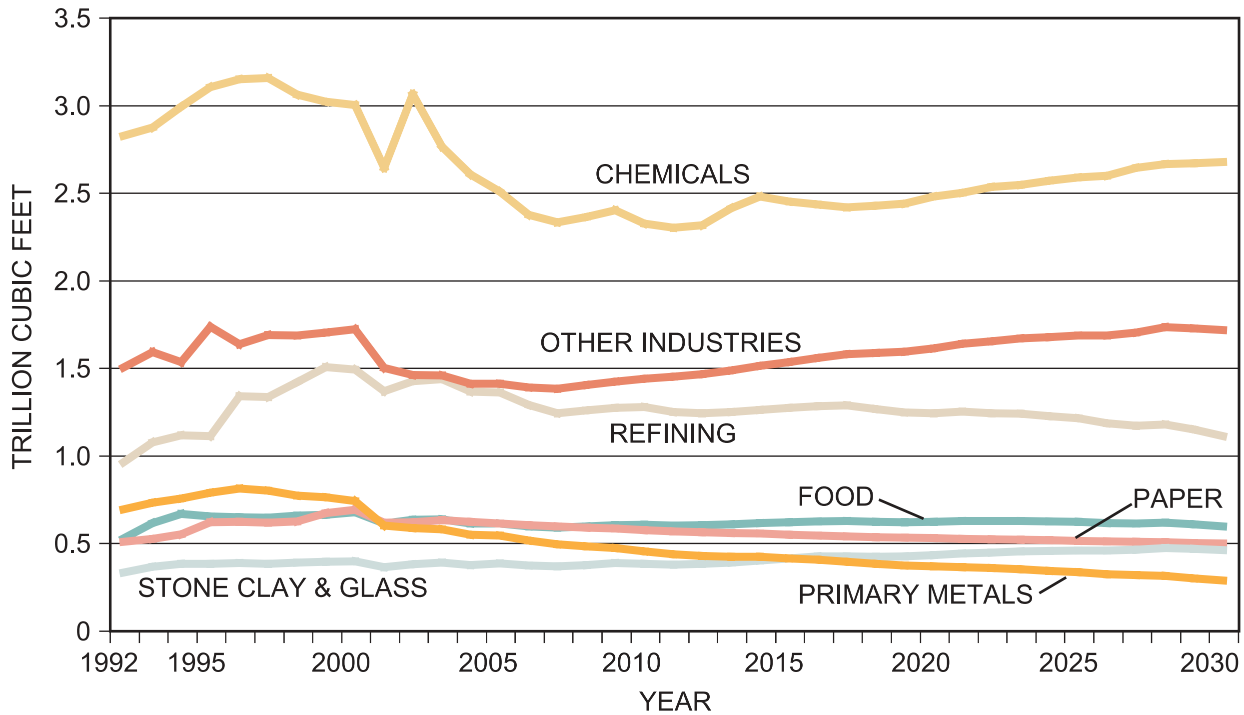


FIGURE 23
INDUSTRIAL GAS CONSUMPTION BY INDUSTRY IN REACTIVE PATH SCENARIO

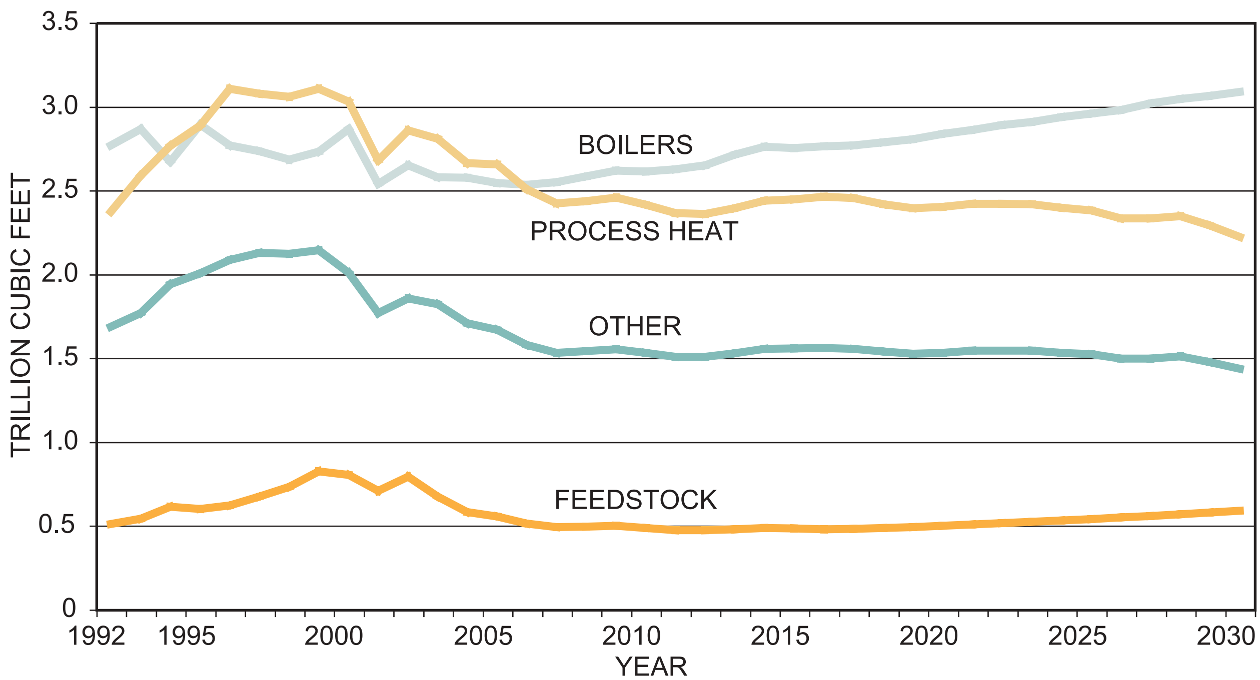


FIGURE 24
LOWER-48 INDUSTRIAL GAS DEMAND BREAKDOWN
(NEW COGENERATION AFTER 1998 NOT INCLUDED)

In the Reactive Path scenario, the most gas-intensive industries are likely to experience little-to-no growth, and would be at risk of permanent relocation to regions of the world that have less-expensive gas supplies. The NPC attempted to understand the implications for gas demand of potential economic dislocations by doing sensitivity analyses of different industrial production rates in the chemicals and primary metals industries. These analyses indicated that a reduced production in these industries would result in reduced natural gas demand. Conversely, an increase in production in these industries, perhaps caused by high economic growth in the U.S. relative to other areas of the world, would result in increased natural gas demand.

In the Balanced Future scenario, industrial demand would still be reduced in the near-term, as higher natural gas prices continue to induce gas-intensive industrial consumers to discontinue some operations and limit investments in North American industrial process capacity. However, if investments in fuel-flexibility and enhanced supplies were facilitated by government policies, industrial consumers in North America would be more competitive on a world scale. There would be less demand erosion, and the financial incentive would exist for construction of additional industrial capacity in North America.

Commercial and Residential Use

Over 60 million U.S. households use natural gas, and over 40% of commercial energy requirements are met by natural gas. Commercial and residential demand growth will reflect demographic shifts, penetration of gas-based technologies, growth in floor space, and levels of energy efficiency. To forecast future natural gas demand in the commercial and residential sectors, the NPC used both an econometric model and a model of capital stock employed. These models considered many variables, including the weather, demographic trends, population growth, responsiveness of these sectors to gas price increases, residential housing stock, the efficiency of the capital stock, commercial floor space, and penetration of gas-based technology.

Commercial and residential natural gas demand is expected to increase in both the Reactive Path and Balanced Future scenarios, due to penetration of gas-based technology, population growth, and growth in floor space, only partially offset by continuing gains in energy efficiency. Energy efficiency is one of the key differences between the two scenarios, with the Balanced Future having greater efficiency gains in residential appliances, commercial equipment, and building standards.

Mexico

Rapidly growing Mexican gas demand and lagging domestic production development will result in Mexico continuing to rely on U.S. gas imports through at least 2005 and likely thorough 2025. Significant unknowns related to both demand and supply give rise to widely varying potentials for imports and exports. This balance ultimately rests on Mexico’s success in attracting foreign participation in its exploration and production industries and its ability to attract LNG imports. Therefore Mexico’s impact on the North American gas balance remains uncertain. Both the Reactive Path and Balanced Future outlooks assume that Mexico will import up to 1.6 BCF/D from the United States in the near term and a net of 700 MMCF/D in the longer term, as illustrated in Figure 25.

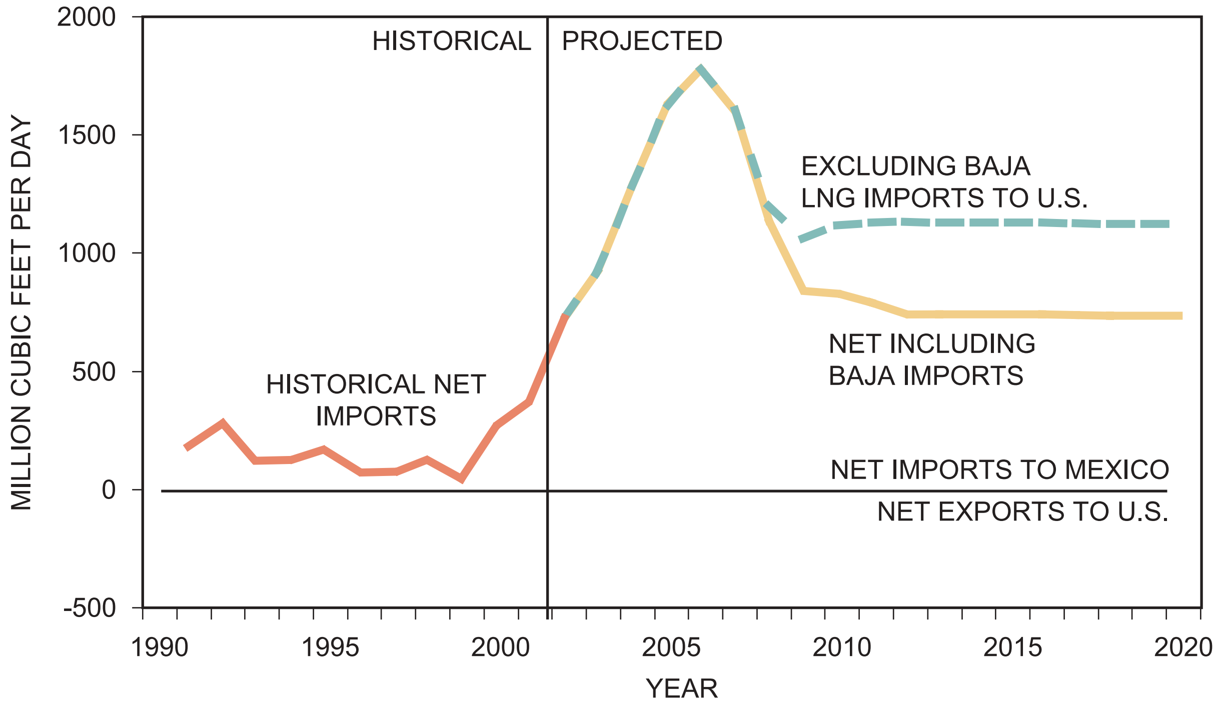


FIGURE 25
MEXICO IMPORT/EXPORT BALANCE

Key Uncertainties in Natural Gas Demand

Natural gas demand varies seasonally, and grows or decreases from year-to-year based on a wide number of factors that were considered in the modeling of both the Reactive Path and the Balanced Future scenarios. The respective effects of key uncertainties were evaluated with sensitivity analyses, and are discussed in the Integrated Report. Those factors with the largest impact on the demand for natural gas are weather cycles, North American and worldwide economic activity, crude oil prices, and changing regulations including the potential for limits on carbon dioxide emissions.

FINDING 5: TRADITIONAL NORTH AMERICAN PRODUCING AREAS WILL PROVIDE 75% OF LONG-TERM U.S. GAS NEEDS, BUT WILL BE UNABLE TO MEET PROJECTED DEMAND.

The NPC undertook a comprehensive review of the North American resource base. As described in earlier studies, there is a large North American gas resource base that will play a key role in providing future natural gas supply. A key aspect of this review, and a stepout from previous NPC studies, was a detailed analysis of production performance over the past ten years. Evaluating historical performance is one way to gain an understanding of current production and to build a sound basis for establishing future projections. This review used historical well production data from the lower-48 states and western Canada to analyze initial production rates, production decline rates, and total well recoveries for each major producing basin.

The key finding from this analysis was that, on average, initial production rates from new wells have been sustained through the use of advancing technologies; however, production declines from these initial rates have increased significantly, and recoverable volumes from new wells drilled in mature producing basins have declined over time, as shown in Figure 26.

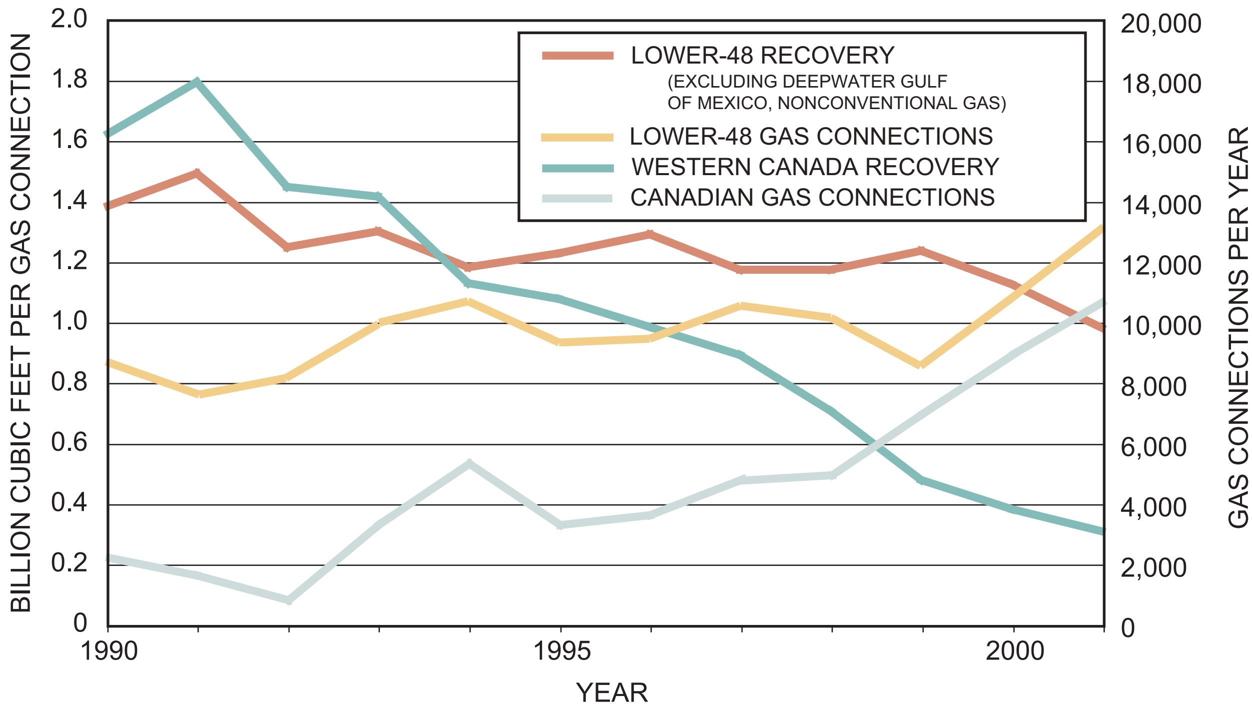


FIGURE 26
RECOVERY PER GAS CONNECTION

Declining well recoveries and higher initial decline rates for new wells are characteristics of many producing basins. This is the underlying reason that the annual rate of decline for North American production continues to increase, and why it is often said that producers are "running harder to stay even." Figure 26 also shows how drilling activity has increased, a trend that has tended to offset the effect of the declining well recoveries.

Without the benefit of new drilling, indigenous supplies have reached a point at which U.S. production declines by 25-30% each year, as shown in Figure 27. In other words, new wells must make up that volume each year before any growth from prior year levels can be achieved. Figure 28 shows how the lower-48 base production is expected to decline and the level of new production that must be achieved from future drilling in the Reactive Path case. Eighty percent of gas production in ten years will be from wells yet to be drilled. The future gas wells that are required for this production outlook are shown in Figure 29. Small, independent producers, who account for about 70% of U.S. production, will drill most of these wells.

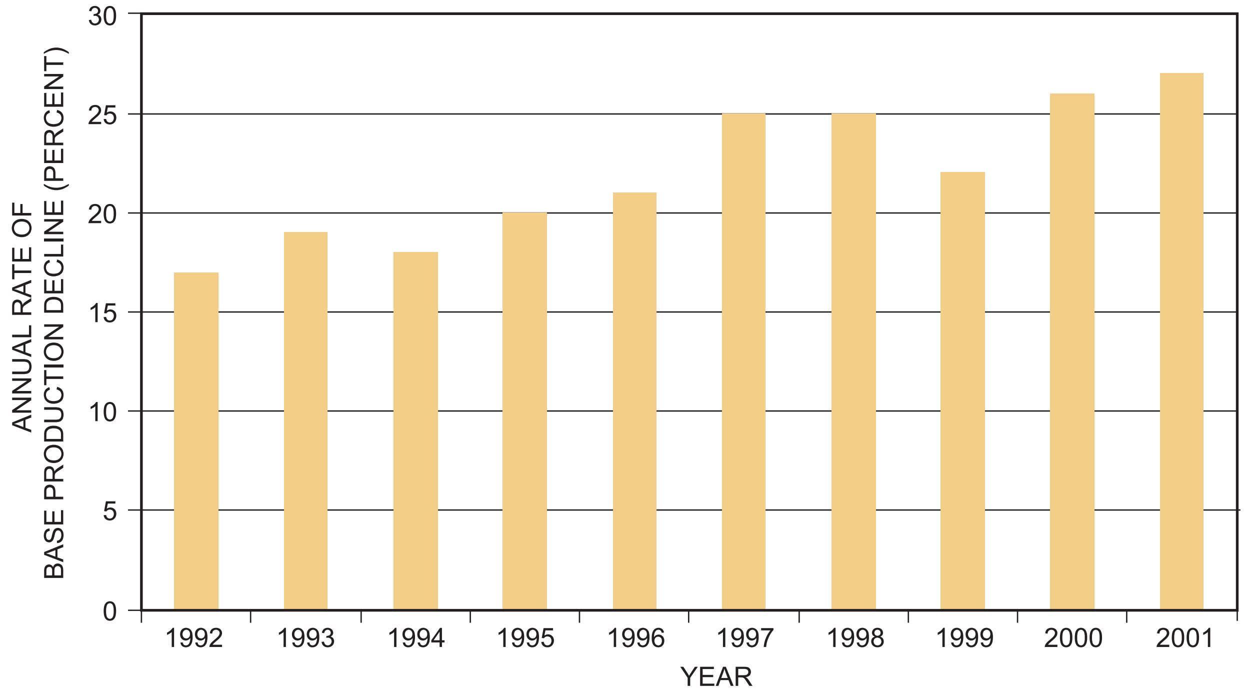


FIGURE 27
LOWER-48 BASE DECLINE RATE

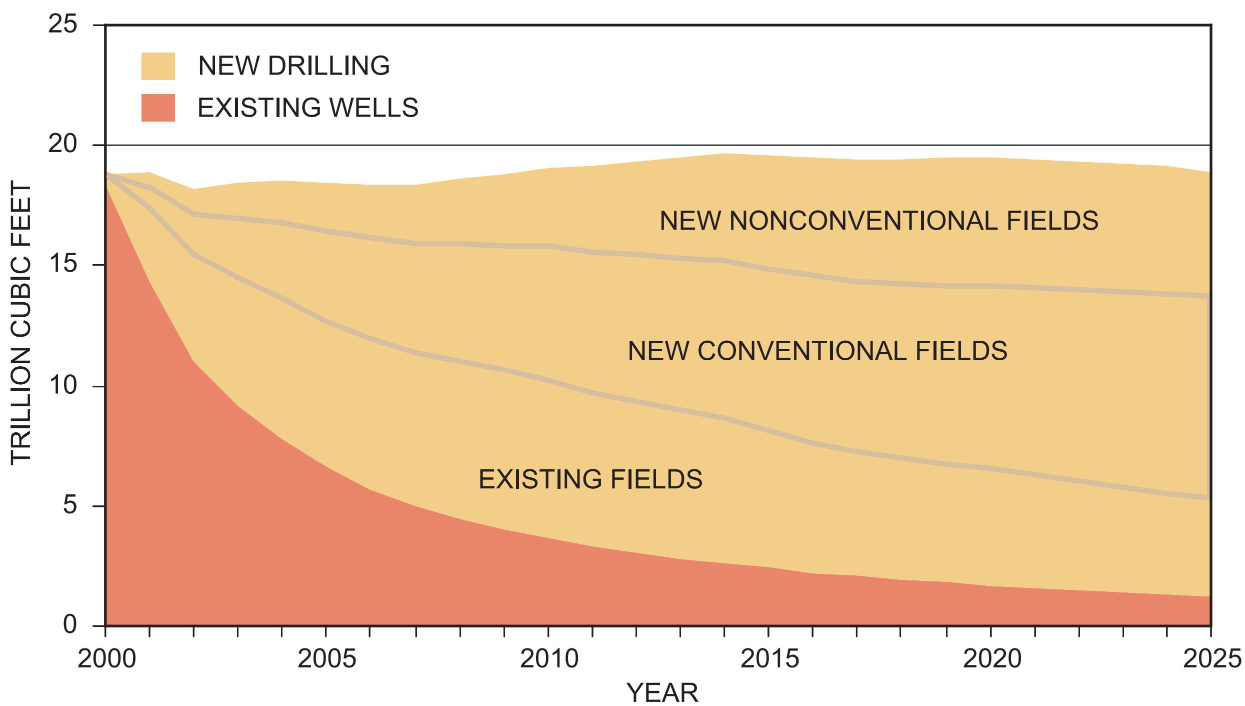
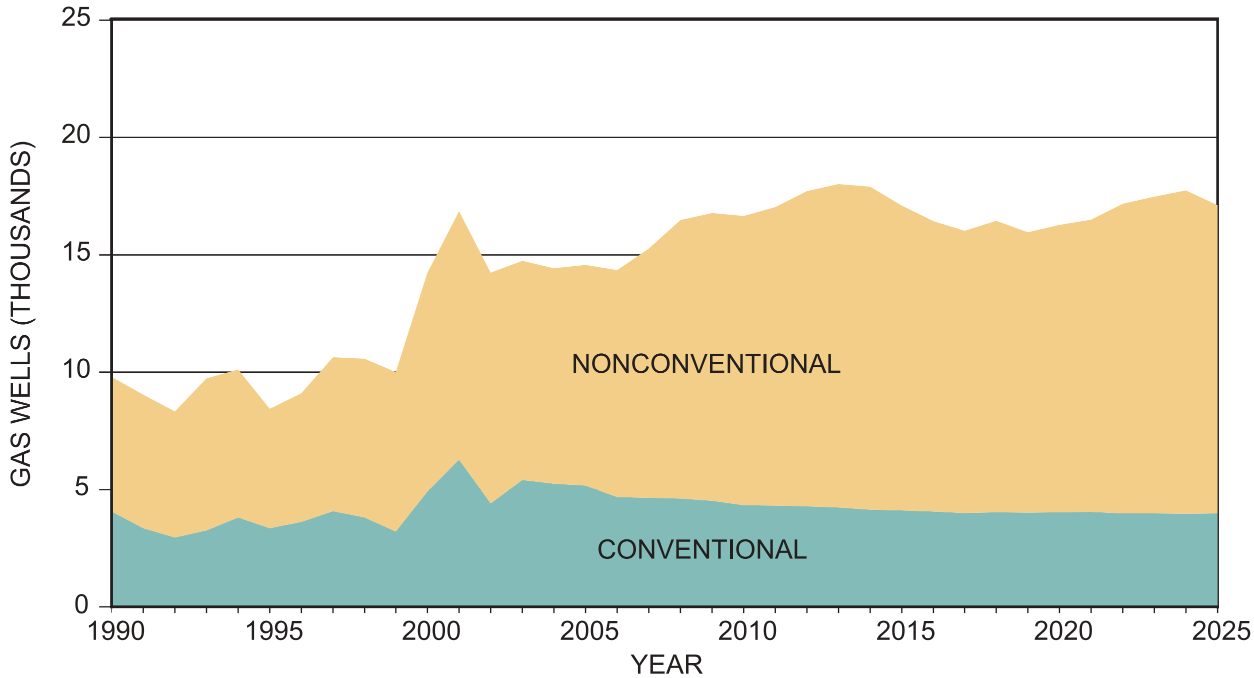


FIGURE 28
LOWER-48 PRODUCTION, EXISTING AND FUTURE WELLS



Note: Historical splits are estimated.

FIGURE 29
LOWER-48 ONSHORE GAS WELLS

The gas drilling activity projected is an increase from the levels of the 1990s, but is consistent with the levels industry has operated at over the past few years. In this outlook, the number of nonconventional wells drilled is increasing, offsetting the projected decline in conventional wells. Given the shorter drilling time for nonconventional wells, this results in a relatively flat outlook for gas drilling rigs during the study period.

This production outlook not only requires a continued high level of drilling activity, but also assumes continued improvement in technologies that increase recovery, reduce costs, and improve drilling success rates. The resources to be found and developed over the next 25 years will be more technologically challenging. These resources will come from reservoirs that are smaller, deeper, and/or lower in permeability. Technology will play a key role in commercializing these resources. Of the projected production in 2025, 14% is attributable to expected advances in technology. This contribution is discussed in detail in the Technology section of the Supply Task Group Report.

To understand the effects of increased drilling activity, the NPC analyzed the supply response from the lower-48 states associated with the doubling of rig activity in 2000/2001. There were limited opportunities in more prolific areas. Most of the additional drilling occurred in basins where low initial rates and low well recoveries were to be expected. Thus, the supply response was less than 5% of lower-48 production even with a doubling of rig activity. In addition, production levels quickly fell when rig activities declined. Figure 30 shows the limited supply increase in response to the doubling of drilling activity.

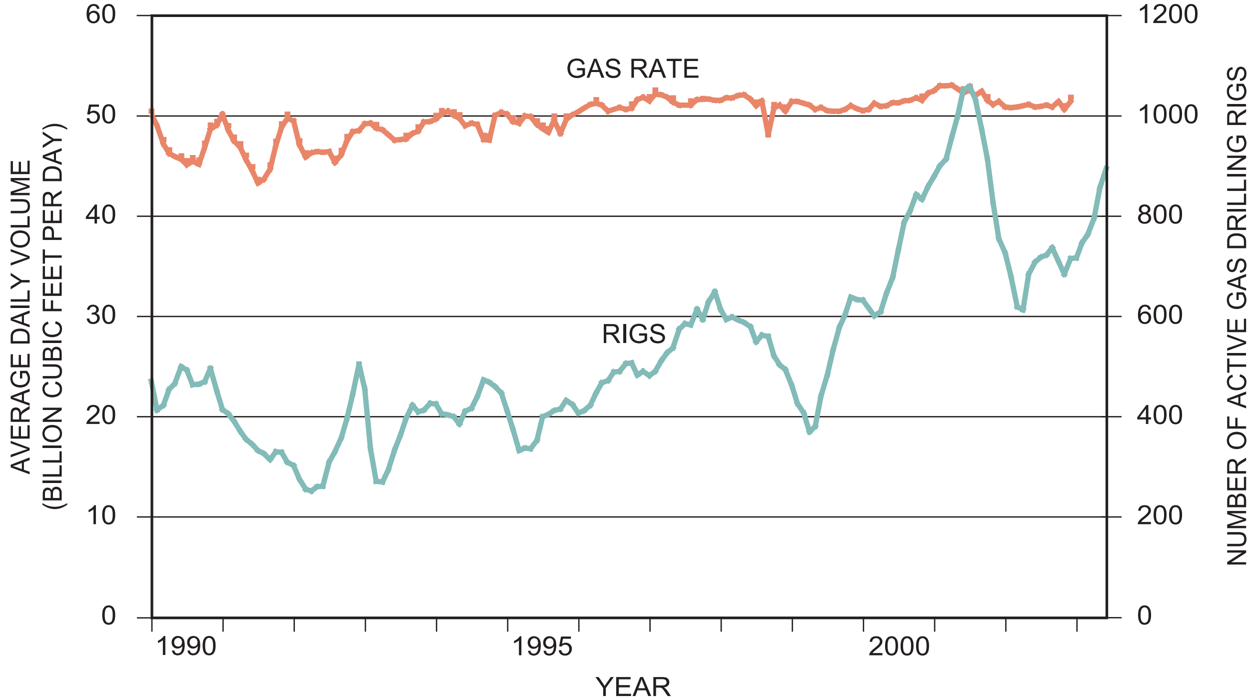


FIGURE 30
MONTHLY LOWER-48 DRY GAS PRODUCTION

Based on analysis of the lower-48 and Canadian resource base and on production performance data, the NPC has concluded that conventional gas production will inevitably decline, and that the overall level of indigenous production will be largely dependent on industry's ability to increase its production of nonconventional gas. Nonconventional gas includes gas from tight formations, shales, and coal seams. Given the relatively low production rates from nonconventional wells, the analysis further suggests that even in a robust future price environment, industry will be challenged to maintain overall production at its current level. This conclusion is reached even though new discoveries in mature North American basins represent the largest contribution to future supplies of any component of this supply outlook. Figures 31 and 32 show projections of the Reactive Path case for production by resource type and from each of the key producing regions.

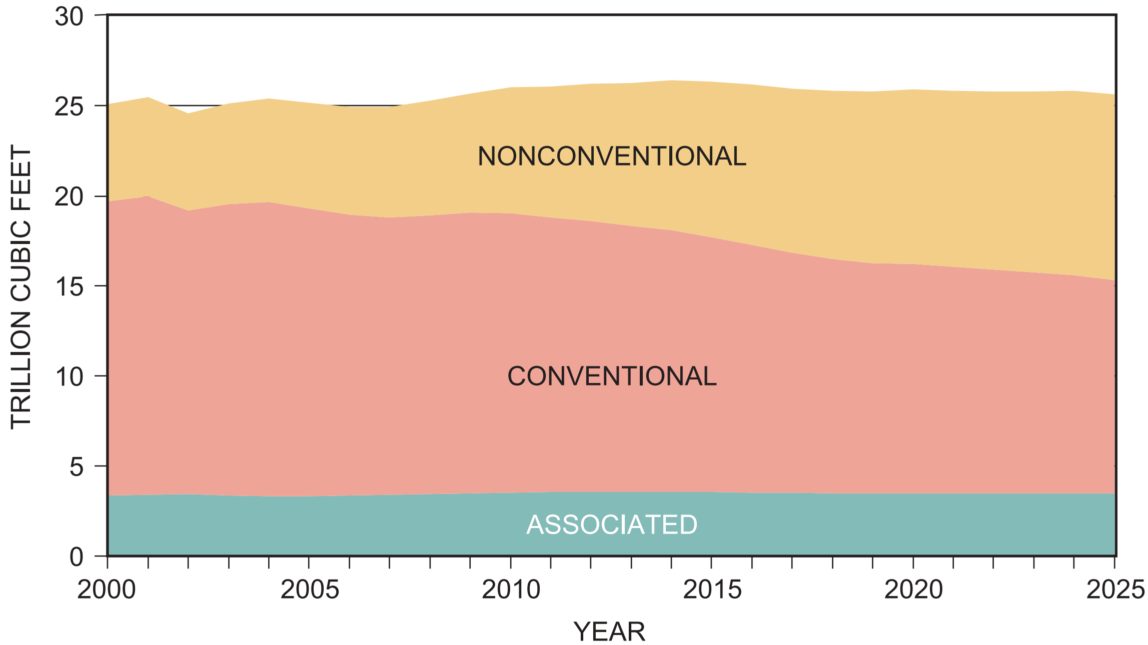


FIGURE 31
U.S. LOWER-48 AND NON-ARCTIC CANADIAN GAS PRODUCTION BY TYPE

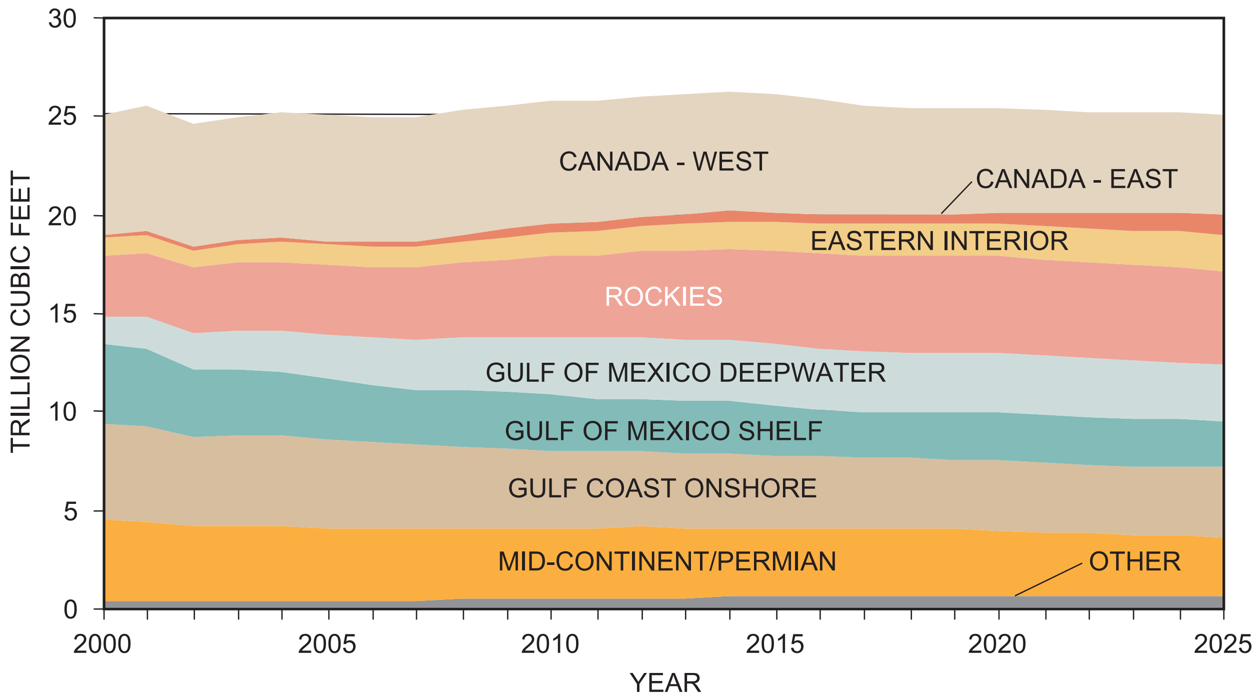


FIGURE 32
U.S. LOWER-48 AND NON-ARCTIC CANADIAN GAS PRODUCTION BY REGION

Although most of the regions are expected to continue to decline with time, some key areas are likely to grow enough to partially offset this decline. Notably, growth in production should occur from the deep waters of the Gulf of Mexico slope, which effectively offsets decline in the more mature, shallower waters of the Gulf of Mexico shelf. In addition, significant growth is expected in production of nonconventional gas, principally in the Rocky Mountains, which effectively offsets declines in other areas.

The NPC estimates that production from the lower-48 states and non-Arctic Canada can meet 75% of U.S. demand through 2025. However, these indigenous supplies will be unable to meet the projected natural gas demand.

FINDING 6: INCREASED ACCESS TO U.S. RESOURCES (EXCLUDING DESIGNATED WILDERNESS AREAS AND NATIONAL PARKS) COULD SAVE $300 BILLION IN NATURAL GAS COSTS OVER THE NEXT 20 YEARS.

Access to indigenous resources is essential for reaching North America's full supply potential. New discoveries in mature North American basins represent the largest component of the future supply outlook, including potential contributions from imports and Alaska. However, the trend towards increasing leasing and regulatory land restrictions in the Rocky Mountain region and the Outer Continental Shelf (OCS) is occurring in precisely the areas that hold significant potential for natural gas production.

In the Rocky Mountain areas, previous studies have evaluated the effects of federal leasing stipulations. This study expanded those evaluations to include post-leasing conditions of approval on both public and private lands to more fully quantify the effect of regulatory processes on resource development. The NPC created a comprehensive model incorporating key wildlife habitat and simulated the effects of regulatory processes on development activities. The results of this analysis are summarized for four key basins in Figure 33.

CATEGORY	GREEN RIVER	UINTA PICEANCE	POWDER RIVER	SAN JUAN
NO LEASING (% RESOURCE)	7%	4%	4%	5%
PROHIBITIVE CONDITIONS OF APPROVAL (%)	36%	17%	34%	6%
ADDED COSTS PER WELL (THOUSANDS)	$55 - 100	$55 - 110	$20 - 60	$35 - 55
TIME DELAY PER WELL (MONTHS)	12 - 22	8 - 13	7 - 14	6 - 8

FIGURE 33
EFFECT OF CONDITIONS OF APPROVAL ON ROCKY MOUNTAIN RESOURCE DEVELOPMENT

Overall, restrictions from conditions of approval were found to be more of an impediment to development than leasing stipulations. For example, in the Green River basin, 7% of the area was unavailable for leasing. A further 36% of the area was available for leasing, but was "effectively" off-limits to development due to prohibitive conditions of approval, bringing the total area not available to development to 43%. In addition, conditions of approval added cost and time delays.

In total, the study found that 69 TCF, or 29%, of the Rocky Mountain area technical resource base is currently "effectively" off-limits to exploration and development, and that access-related regulatory requirements impacted an additional 56 TCF of potential resource with added costs and delays to development. The details of the methodology used to develop this assessment are included in the Access section of the Supply Task Group Report.

Leasing moratoria in the Eastern Gulf of Mexico, Atlantic Coast, and the Pacific Coast currently prohibit access to these areas of the OCS. The NPC has estimated that 80 TCF of technically recoverable resources potentially underlie these moratoria areas. It should be noted that limited data have been acquired in these areas due to the moratoria so the range of uncertainty with regard to the size of this resource is large. Figure 34 shows the major regions of the lower-48 states with such access constraints and the volume of technical resource restricted from exploration and development.

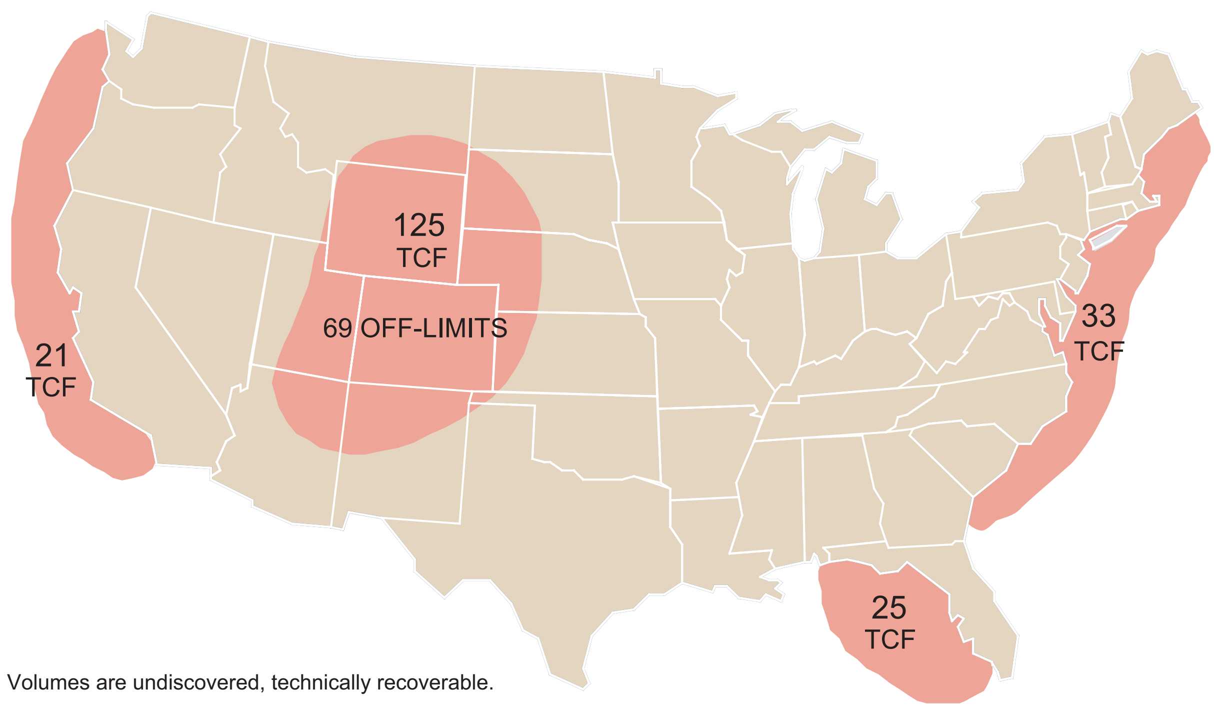


FIGURE 34
LOWER-48 TECHNICAL RESOURCE IMPACTED BY ACCESS RESTRICTIONS

The NPC evaluated the effect of removing the OCS moratoria and of reducing the impact of conditions of approval on the Rocky Mountain areas. These changes could potentially add 3 BCF/D to production by 2020. In addition, this increased production was found to reduce average price projections by $0.60/MMBtu (nominal dollars), which translates into a reduction in the cost of natural gas to consumers of about $300 billion over a 20-year period. This outlook is reflected in the Balanced Future case, and can play an important role, along with other new supply sources, in meeting the projected natural gas demand.

FINDING 7: NEW, LARGE-SCALE RESOURCES SUCH AS LNG AND ARCTIC GAS ARE AVAILABLE AND COULD MEET 20-25% OF DEMAND, BUT ARE HIGHER-COST, HAVE LONGER LEAD TIMES, AND FACE MAJOR BARRIERS TO DEVELOPMENT.

With the outlook for production from the U.S. lower-48 and non-Arctic Canada flat to declining, new sources of supply will be required to meet the projected growth in natural gas demand. Both the Reactive Path and Balanced Future cases project liquefied natural gas and Arctic gas to become major supply sources, providing 20-25% of U.S. demand by 2025. These new sources also diversify the natural gas supply beyond traditional indigenous sources, and provide access to the rapidly developing global LNG market.

Liquefied natural gas is already a significant supply source for many countries in the world, including Japan, South Korea and several west European nations. Fortunately, the world's gas resource base is large. The NPC analysis concludes that significant quantities of LNG will need to be imported into the United States in the future to meet the expected demand for natural gas. LNG has a proven safety record with 33,000 carrier voyages covering 60 million miles with no major accidents over a 40-year history. Historically, LNG imports into the United States have contributed less than 1% to U.S. supply, primarily due to low gas prices and the relatively high cost of LNG. This situation has changed. New technology has reduced the cost of making and transporting LNG. New LNG supply sources have also begun to enter the market and, because of higher gas prices, are now competitive in the North American market. Figure 35 illustrates the diverse global natural gas supply sources for LNG.

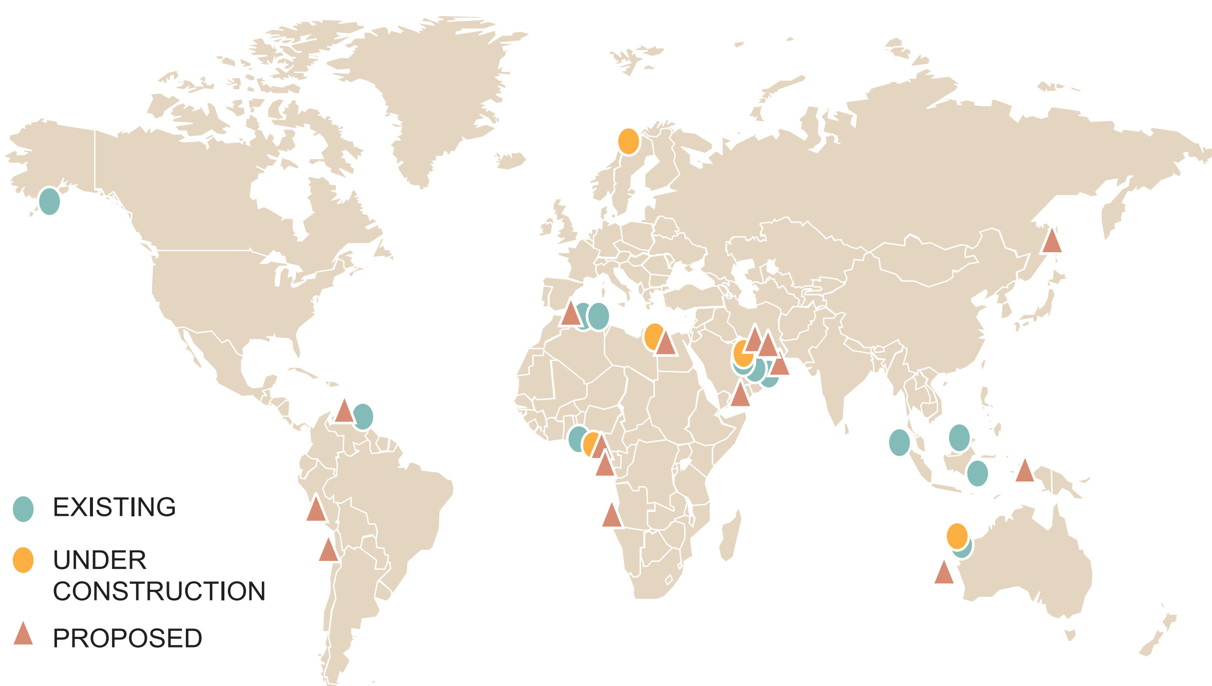


FIGURE 35
GLOBAL LNG SUPPLY

The Reactive Path case assumes the four existing U.S. regasification terminals will be fully utilized by 2007, and that seven additional regasification terminals (and seven expansions) will be built in North America to meet gas demand through 2025. This would result in a total LNG import capacity of 12.5 BCF/D, with LNG providing 14% of the U.S. supply of natural gas by 2025. In the Balanced Future case, projects are permitted more quickly and two additional terminals and two additional expansions are assumed built. This increases total LNG import capacity to 15 BCF/D or 17% of the U.S. supply of natural gas by 2025. Figure 36 shows the locations of existing and potential new LNG terminals, and Figure 37 shows the projected volume contribution from LNG.

FIGURE 36
NEW NATURAL GAS SUPPLY SOURCES

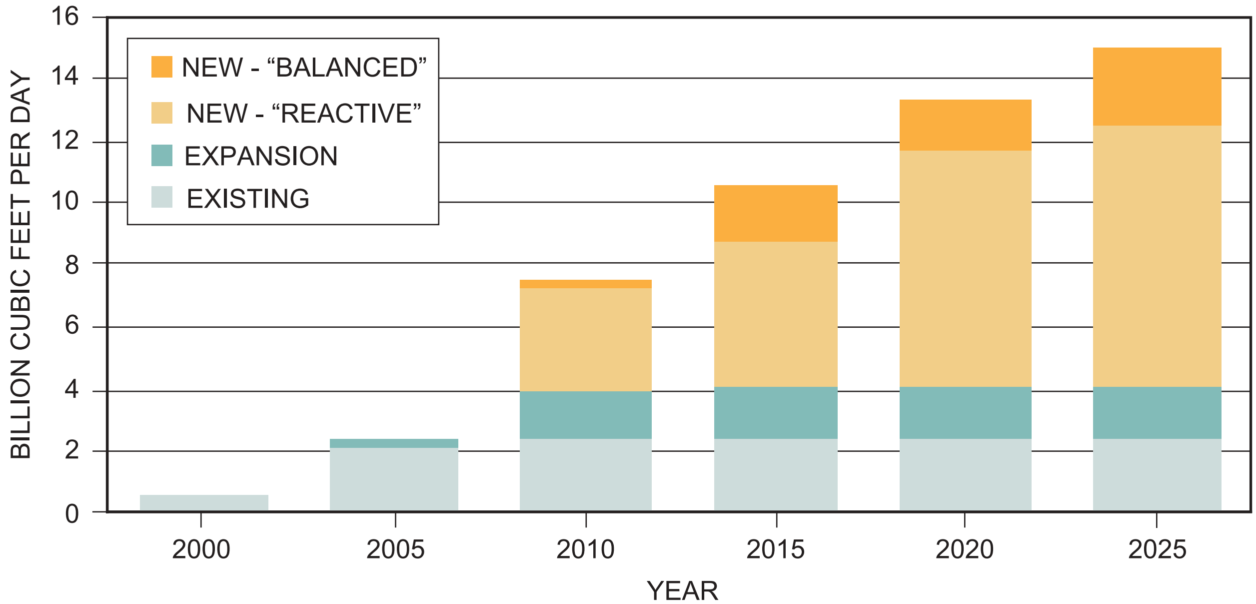


FIGURE 37
NORTH AMERICAN LNG IMPORTS

While there is clear potential for LNG imports to fall short of these projections due to market uncertainties and possible opposition to siting of LNG regasification terminals, the upside potential, while significant, is also uncertain. One implication of natural gas price projections in the Reactive Path case is that even larger quantities of imports might be attracted. However, LNG developments will also be subject to the risk of lower North American demand due to higher prices, as well as competition from other North American sources of natural gas production.

The assumptions in either case represent a major undertaking, since developing a large, new LNG import capability in North America will not be easy. LNG imports require alignment of the entire supply chain from development of foreign source gas reserves, to liquefaction of the supply, to construction of specialized LNG carriers, to regasification and delivery into the North American transmission infrastructure. Capital requirements for a typical LNG development from source to an interconnection with an existing pipeline grid are on the order of $5-$10 billion per BCF/D of capacity. For the Reactive Path case, the estimated capital requirements for LNG during the study period are over $90 billion, and nearly $115 billion for the Balanced Future case.

The typical regasification terminal in the United States is estimated to take over five years from initial permit application to commencement of imports. Under current regulations, permitting can take from one year (offshore terminals) to over two years (onshore terminals) assuming minimal resistance and a well-coordinated permitting process. The Reactive Path case assumed a permitting time of two years, while the Balanced Future case assumed one year.

Recently, the U.S. government implemented two policy changes to facilitate development of new LNG import regasification terminals. First, the Deep Water Port Act was amended to include natural gas/LNG/CNG; this resulted in two significant changes for offshore LNG import terminals. Such terminals will now be under the jurisdiction of the United States Coast Guard, and permit applications will have a discrete timeline. Second, the Federal Energy Regulatory Commission, which has the jurisdictional authority for onshore LNG import regasification terminals, ruled that two such terminals will be treated similarly to gas processing plants, no longer requiring open-access regulation. The latter policy allows companies to develop integrated LNG projects, which is important in reducing the risk associated with these large, complex, projects.

These efforts, while encouraging new LNG import terminal development, will not overcome all the hurdles faced by the industry. New terminals may face substantial local opposition. Permits for new terminals, particularly onshore terminals, will only be issued in a timely fashion with the support of local governments and communities. A continued leadership role, as demonstrated by FERC in the recent reactivation of the Cove Point and Elba Island facilities, will be needed to move the permitting process forward in a timely manner. Any setbacks from what the NPC projects as substantially successful development of LNG supply would reduce projected supplies and increase gas prices.

To evaluate the impact of potential setbacks, a sensitivity case was evaluated in which only two new LNG terminals were constructed due to permitting difficulties. In this case, LNG import capacity was reduced by 6 BCF/D and the average gas price increased by 10%. Clearly the ability to import increasing volumes of LNG is important to achieving a more comfortable supply/demand balance.

A second source of significant potential new supplies is Arctic gas. This includes gas from the Alaska North Slope and the Mackenzie Delta region in Canada (illustrated in Figure 36) where substantial quantities have already been discovered, but require long, new pipelines to be developed.

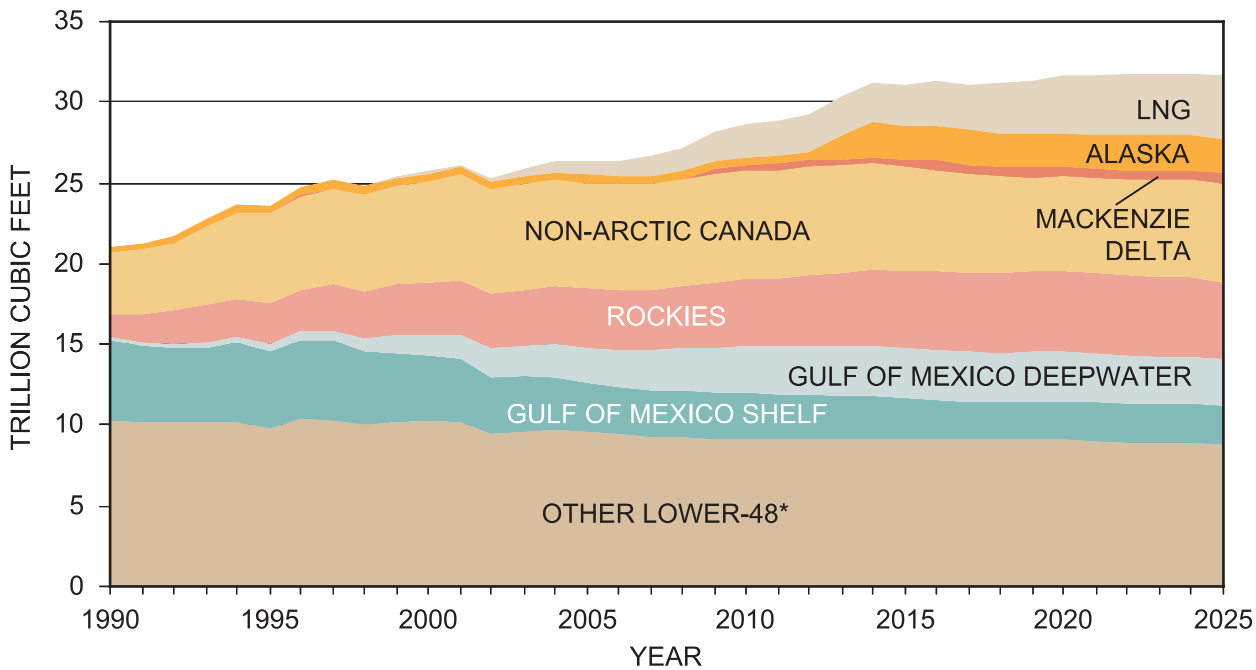
Efforts have been underway by industry for over 30 years to commercialize Alaskan gas. Major hurdles for commercializing this resource include costs, permitting, state fiscal uncertainty, and market risks. The companies involved in oil and gas production at Prudhoe Bay, Alaska estimate the cost to bring Alaskan gas to U.S. markets to be on the order of $20 billion with a lead time of ten years, assuming construction of full pipeline infrastructure south of Alberta to U.S. markets. The NPC study analysis indicates some capacity may be available in existing infrastructure, potentially reducing the amount of new pipeline construction required.

Industry is working to advance new technology that could reduce the capital cost. However, securing all the necessary permits in a timely manner from various jurisdictions in the United States and Canada represents a significant challenge. Another hurdle is the uncertainty regarding how royalty and tax payments to the state of Alaska will be calculated over the life of a pipeline project. Conditions must be particularly strong to support an investment of this magnitude considering the long lead-time and the inherent risks. The NPC has assumed that these challenges will be overcome, and that conditions will support an Alaska gas pipeline start-up in the 2013-14 time frame. This would contribute 4 BCF/D, about 6% of U.S. supply, through the remaining years of the study period.

Given the commercial, regulatory, and cost-related risks associated with this project, a sensitivity case was run in which it was assumed that the Alaska gas pipeline will not be built. This increased gas price projections by roughly 8% over the period from 2015 to 2025, putting further stress on the economy and illustrating the importance of this project to the overall outlook.

Similar issues confront a proposed pipeline from the Mackenzie Delta in Canada. Although that project is smaller, and most of the gas will probably find a market in Canada, there will be an effect on the U.S. gas supply. A Canadian regulatory process is evolving to address First Nations' rights as well as other local and federal issues in a timely manner. The NPC has assumed that permits can be secured and market conditions could support start-up of a Mackenzie Delta pipeline in 2009 at a rate of 1 BCF/D, with an expansion in 2015 to 1.5 BCF/D.

All of these projects face barriers to development and have very long lead times. Thus these potential sources of supply will not affect the short-term fundamentals of the current market environment. Figure 38 shows the relationship of these new supply sources to other sources of supply in the Reactive Path case.



* Includes lower-48 production, ethane rejection, and supplemental gas.

FIGURE 38
U.S. AND CANADIAN NATURAL GAS SUPPLY

The NPC also evaluated potential new supply sources that require technology advances to be commercially competitive. These new sources, including methane hydrates are viewed as unlikely to make material contributions prior to 2025, but they do represent potential longer-term supply sources. Additional details can be found in the Technology section of the Supply Task Group Report.

FINDING 8: PIPELINE AND DISTRIBUTION INVESTMENTS WILL AVERAGE $8 BILLION PER YEAR, WITH AN INCREASING SHARE REQUIRED TO SUSTAIN THE RELIABILITY OF EXISTING INFRASTRUCTURE.

Figure 39 illustrates expected capital expenditures for infrastructure through 2025 for the Balanced Future case (the results of the Reactive Path case are very similar). Through 2025 it is anticipated that in the United States, $35 billion ($1.5 billion per year) will be invested in new and expanded pipeline and storage infrastructure to provide deliveries of new supply sources to the marketplace. Additionally $12 billion in pipeline and storage infrastructure expenditures is projected for Canada. Nearly $70 billion ($3 billion per year) will be required for distribution facilities in the United States (twice the rate for pipeline and storage).

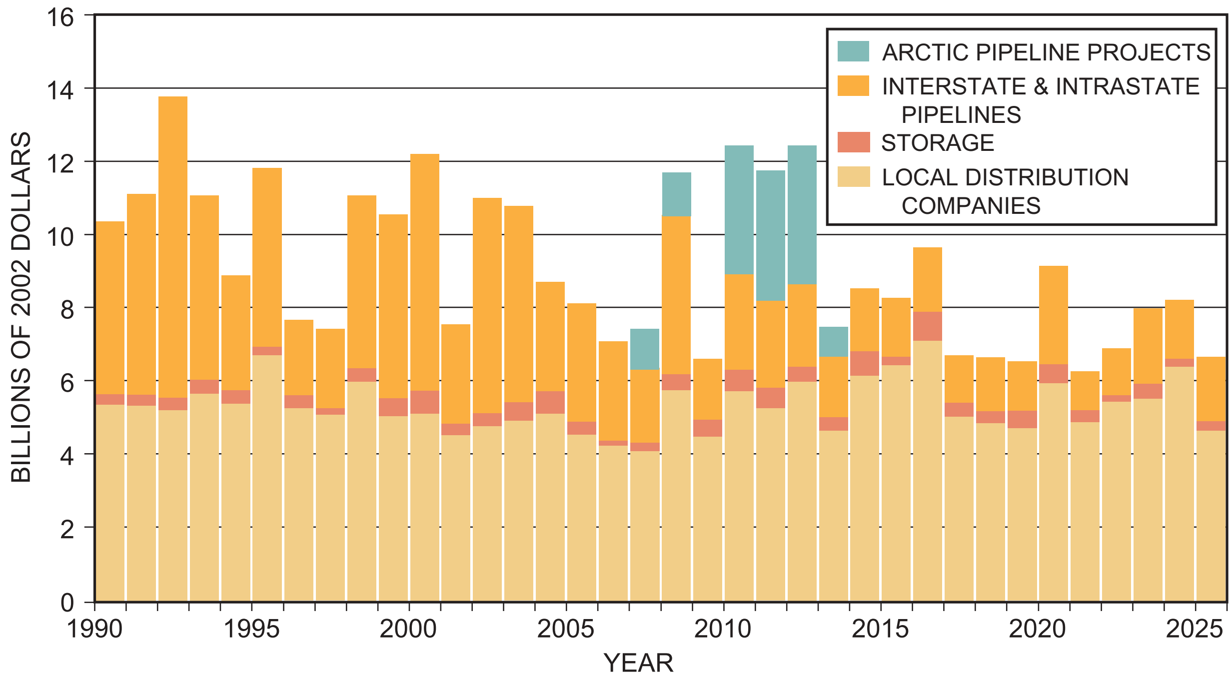


FIGURE 39
NORTH AMERICAN CAPITAL EXPENDITURES FOR TRANSMISSION, DISTRIBUTION, AND STORAGE

As can be seen, the projected need for capital for new infrastructure is decreasing in the future while sustaining capital is becoming an increasing percentage of total capital requirements. It is anticipated that over the next 22 years $70 billion of expenditures will be needed in sustaining capital for the existing pipeline and distribution infrastructure in the United States, and $3 billion in Canada. 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.

As discussed previously, growth in onshore production in the lower-48 states is effectively limited to the Rocky Mountain region. Major new sources of gas will have to come from outside the lower-48 states and will rely on the existing network of nearly 290,000 miles of high-pressure pipelines to transport the gas to markets. Figure 40 shows the anticipated new pipeline transmission requirements in the Balanced Future case by 2025**.**

FIGURE 40
NEW PIPELINE AND LNG CAPACITY
(MILLION CUBIC FEET PER DAY) CHANGE FROM 2003 TO 2025

Major new pipeline infrastructure will be needed to bring Arctic production to the Alberta hub. The additional capacity needed to move the Arctic gas away from the Alberta hub is a function of the rate of decline of Western Canadian Sedimentary Basin (WCSB) production, which is anticipated to continue its decline as the Arctic gas comes on line, and growth in demand for gas in Canada, including an increasing gas demand for oil sands development. Currently, there is about 15 BCF/D of pipeline capacity from western Canada and it is about 85%-utilized in transporting WCSB gas to downstream markets. The NPC analysis suggests that an additional 0.5 to 2 BCF/D of new or expansion capacity will be required with the remainder moving on existing pipeline infrastructure.

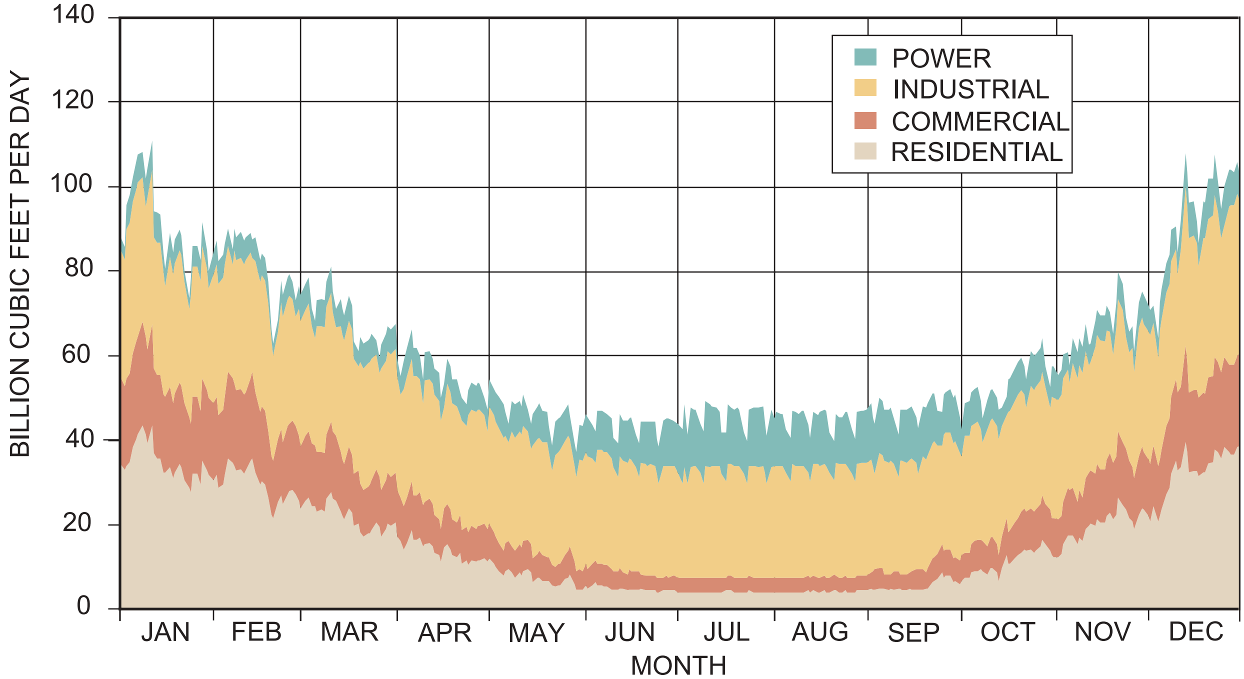
The NPC outlook indicates that LNG import terminals are a critical element needed to meet demand on the east and west coasts. To the extent that these LNG regasification terminals can be sited close to demand centers, additional pipeline infrastructure investment may be minimized, particularly where existing capacity is made available by declines in domestic production. If such terminals cannot be sited in market regions, however, additional pipeline infrastructure and greater reliance on the existing pipelines from the Gulf Coast may be needed to deliver LNG to major markets. This will result in higher basis between Henry Hub and the market and higher costs for consumers.

Additional pipeline take-away capacity will also be needed from the Rocky Mountains, deep waters of the Gulf of Mexico, and Eastern Canada offshore. This new capacity will be limited to that needed to interface the existing pipeline grid. From there, it is expected that the gas will move on existing pipeline systems to access markets throughout the lower-48 states.

Capacity must also be constructed to transport gas from storage to market centers. Mid-Atlantic and Northeast markets will require additional storage. Since the lack of suitable reservoirs restricts the potential development of this storage capacity to the western portions of Pennsylvania and New York and Eastern Ohio, incremental short-haul pipeline capacity of approximately 2 BCF/D will have to be constructed to the major northeastern market centers, which include New York City, Boston, and Philadelphia.

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 is fairly 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, industrial demand is projected to grow by only 3%. This means 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 41 and 42, 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 and unpredictable than that of a traditional residential/commercial load profile. The growing summer peak impacts the summer season gas storage injection period, primarily allowing for injections only in the off-peak electric demand hours of the day and thus requiring more volume to be injected into storage during the shoulder months of April through June and September through October, historically lower demand.



Source: Energy and Environmental Analysis, Inc.

FIGURE 41
1997 DAILY LOADS
FOR THE UNITED STATES AND CANADA

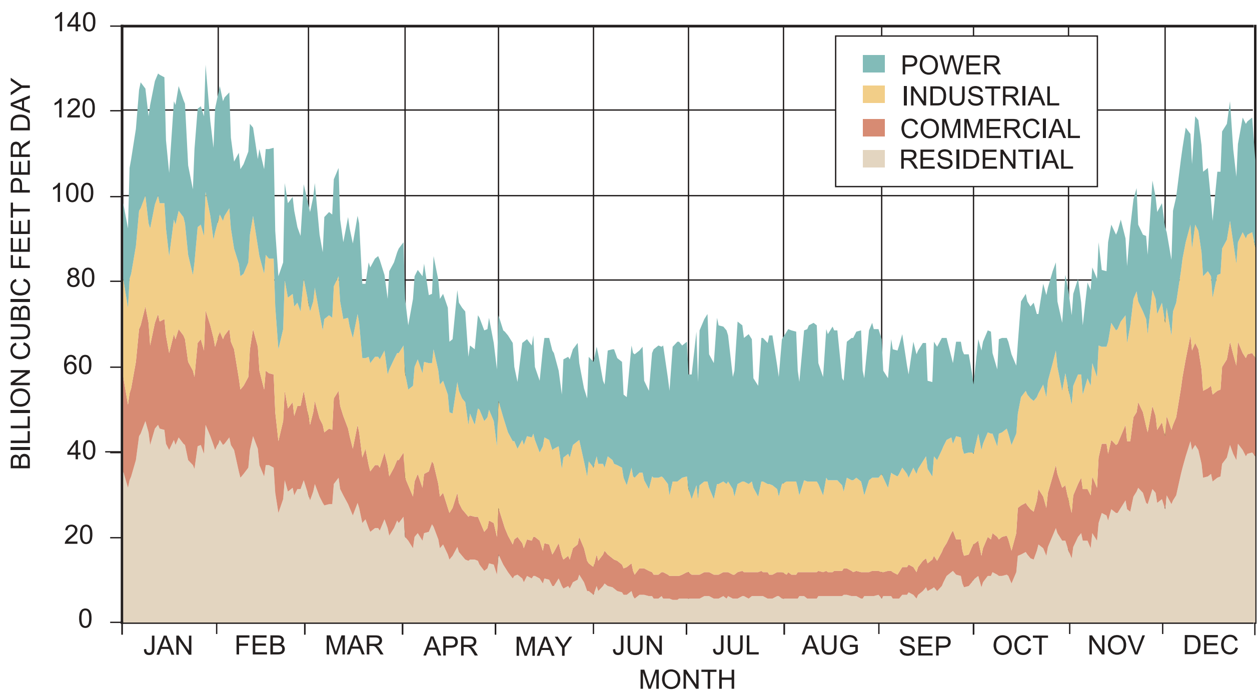


FIGURE 42
2025 DAILY LOADS
FOR THE UNITED STATES AND CANADA

Regardless of the growing power generation needs in the summer months, local distribution companies (LDCs) will need to fill their market area storage to be able to meet their customer's winter consumption requirements reliably. The growing divergence of the two sectors' needs will require storage operators to construct additional storage capacity and increase the flexibility of their current facilities.

Construction of significant new LDC facilities will also be required to meet customer demands. These facilities include main reinforcements, main extensions, and the construction of services to bring the gas into an individual home or business. 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[6] and reduce the costs of new construction. A 1% annual gain in productivity from technological advances was assumed in this study. Such a gain would result in reduced customer costs of $300 to $400 million per year, over the costs of the previous year. Therefore, continued R&D is needed to provide new techniques and technologies to minimize these future costs while assuring safe and reliable operation of distribution systems.

Existing Infrastructure

Gas transmission and distribution has been the safest mode of energy transportation. Use of the existing pipeline and distribution infrastructure is anticipated to increase as many lines reverse flow, and others increase in utilization. Significant ongoing expenditures will be required to undertake additional preventative measures to maintain safe and reliable operations. Pipeline and storage companies operate over 290,000 miles of transmission pipe and approximately 16,000,000 horsepower. Of the 290,000 miles, 255,000 miles, or 88%, was installed prior to the 1970s. Figure 43 shows the North American pipeline grid.

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

FIGURE 43
NORTH AMERICAN PIPELINE GRID (24" DIAMETER AND GREATER)

Congress enacted in 2002 the Pipeline Safety Improvements Act, which has significantly increased pipeline testing and reporting requirements for the transmission and distribution industries. In addition to improving the "one call" systems used by the states and requiring enhanced operator qualifications, the Act mandates updated maintenance programs and continuing inspections of all pipelines located in population centers. These mandates will increase costs to consumers several ways. Additional costs will arise because facilities will need to be temporarily taken out of service to perform the mandated testing. This may cause deliverability constraints during testing periods due to reduced capacity. Costs will also increase as a result of the direct costs of integrity inspections and the required modifications of pipeline and distribution facilities. Both of these costs will tend to put upward pressure on gas transportation rates.

Because of the decreasing life expectancy of the installed horsepower and pending and potential environmental mandates, significant horsepower will have to be replaced over the study period. If operators were to replace all horsepower over the next 50 years, 320,000 horsepower would need to be replaced each year. Similarly if all pipe was replaced over the next fifty years, 5,800 miles of pipe would need to be replaced each year. 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 as it is a small fraction of the existing 290,000 miles of pipe and 16,000,000 horsepower of compression, much of which is over 40 years old. 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 Improvements Act, however, we doubled the historical levels for the purposes of the study. If pipelines aren't able to retire the pipe and/or compression in the future due to continuing need or otherwise, sustaining capital could be significantly higher. At some point in the future, however, the progressive aging of pipelines and compressors will result in further significant increases in the miles of pipe and horsepower replaced per year.

FINDING 9: REGULATORY BARRIERS TO LONG-TERM CONTRACTS FOR TRANSPORTATION AND STORAGE IMPAIR INFRASTRUCTURE INVESTMENT.

The average transportation contract term on pipelines has shortened. New pipeline and storage infrastructure are generally financially supported by long-term contracts for a period of ten to twenty years. Companies are less willing to invest dollars in new infrastructure if contract durations for existing or new pipeline/storage capacity are shortened by the impact of regulatory policies. In a free market, shippers make long-term commitments when they see the need for the service that will be provided. If barriers exist to shippers making long-term commitments, investment in new infrastructure is impacted. This affects both new and existing pipelines. As shown in Figure 44, the average contract term on gas pipelines is being shortened. Pipeline operators believe a significant factor is the regulatory policies on contracting practices by some federal and state regulatory agencies. As a result, even though the pipelines were carrying basically the same amount of gas to serve the same markets, the revenue stream is viewed as more short-term in nature and less likely to support long-term infrastructure investments.

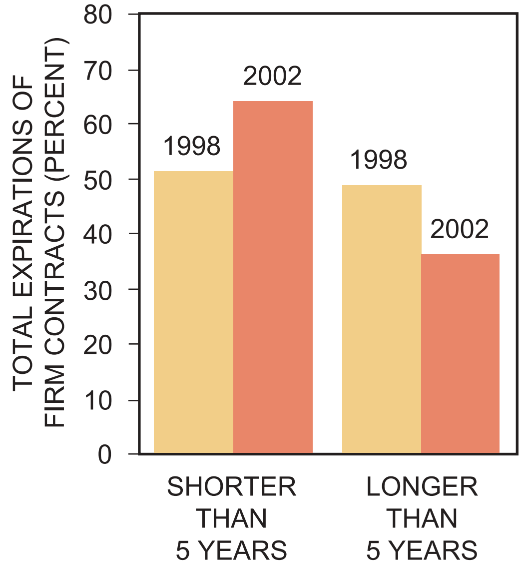


FIGURE 44
FIRM CONTRACT EXPIRATIONS

From the beginning of the transmission industry until recently, LDCs were the dominant parties contracting for long-term pipeline and storage capacity. Their contracts were crucial for the development of new pipelines and the expansion of existing ones because they provided the financial underpinning necessary to raise the required capital. This role began to change in the late 1990s as a result of regulatory changes at the federal and state level. Regulatory changes associated with a competitive market that resulted in the growth of independent marketing companies as sellers of gas to both utilities and to end users gave LDCs more supply options and incentives to contract for less capacity and to hold shorter-term capacity contracts.

Marketing companies saw rapid growth in the early 1990s as they provided the intermediary function between producers and consumers that arose as the pipeline sales function disappeared. LDCs and major industrial consumers became responsible for purchasing their own gas supplies. Most began by buying gas in the production area directly from producers and transporting it to market via their existing contracts. Over time, marketing companies began to offer city gate sales service to LDCs and large end-users by efficiently packaging portfolios of transportation and storage contracts obtained from the original contract holders either through agency agreements, contract releases or, in the later stages, by direct contract ownership. Marketers desired to hold transportation and storage contracts similar in term to their associated sales agreements to lower their financial exposure. Many of the marketers' sales contracts were relatively short term. Some marketer's portfolios held some long term capacity contracts but it was for a much smaller proportion of their portfolio than was common for pipeline customers in the pre-restructuring period. Thus, as illustrated in Figure 44, although the pipelines were carrying basically the same amount of gas to serve the same end-uses, their average contract term shortened.

A contributing factor in the shortening of pipeline contracts was the restructuring of many LDC businesses in the 1990s. The opening of LDC distribution system capacity to transport by third parties was developed as a means to increase competition and lower prices. By the end of the 1990s, restructuring was complete in many states for gas in the industrial and electric generation segments and was underway in the residential/commercial sector. Although retail choice programs are in place in many states, to date the vast majority of residential customers have elected to remain with their original utility. Nevertheless, a directive from some states is that LDCs should not contract for the long term in pipeline, storage, or upstream capacity since their share of the future market was unknown and subject to considerable risk in the face of developing competition. Generally, LDCs are not willing to contract for long-term capacity and take the risk of being second-guessed in future prudency reviews.

Today, the turmoil of the gas marketer business segment has almost eliminated independent and affiliated marketers from the list of prospective purchasers of existing and/or proposed pipeline transmission capacity. Even if such firms wanted to contract for capacity, their creditworthiness may make them too great a risk for pipelines and downstream customers to consider without the gas marketer providing significant credit assurances.

Many LDCs will not enter into long-term contracts with marketers in today's market out of fear that regulators may subsequently deem them imprudent. 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. The result is that regulatory barriers may be inhibiting efficient markets and discouraging the financial incentives to develop and maintain pipeline infrastructure.

FINDING 10: PRICE VOLATILITY IS A FUNDAMENTAL ASPECT OF A FREE MARKET, REFLECTING THE VARIABLE NATURE OF DEMAND AND SUPPLY; PHYSICAL AND RISK MANAGEMENT TOOLS ALLOW MANY MARKET PARTICIPANTS TO MODERATE THE EFFECTS OF VOLATILITY.

Since the 1980s, the natural gas market has continuously evolved following FERC and Congressional actions to implement the free market system for the trade of natural gas. Accompanying this deregulation has been greater variability of gas prices as market forces worked to establish prices in the monthly and daily markets. Price volatility is a natural phenomenon in a market where supply and demand vary on a daily/hourly basis. The principal drivers behind price volatility are supply and demand fundamentals, which include demand variability, weather effects, supply and storage levels, the cost of competing fuels, and overall market trends. Relatively large price changes can and have occurred when supply and/or demand sectors are unable to quickly adjust to unexpected changes in market conditions. Figure 45 shows Henry Hub monthly prices for the last ten years. Natural gas prices have been more volatile than crude oil prices but significantly less volatile than electricity prices. Many consumers and producers have access to a broad range of physical and risk management tools to manage its effects.

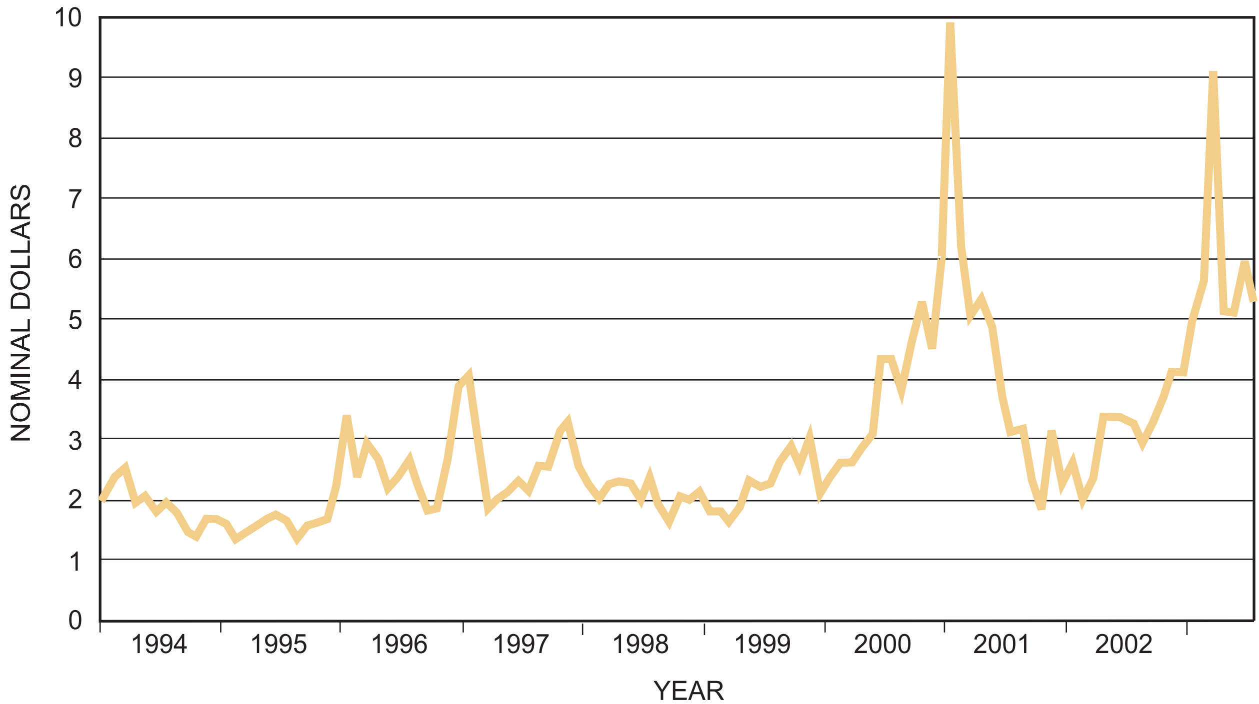


FIGURE 45
HENRY HUB MONTHLY INDEX PRICES

The North American natural gas market is the largest and most liquid gas market in the world, with hundreds of suppliers and thousands of major consumers including LDCs, industrials, and power generators. The market is functioning efficiently with lessened government involvement following years of regulatory reform. In a free market, participants need price signals in order to make rational decisions about whether to produce or consume more gas. Customers who want gas, even in the highest demand periods, get their gas if they contract for delivery in advance – or alternatively pay the market price on the day. Additionally, producers respond to price signals for increased supply by increasing their exploration and drilling efforts.

Most residential and commercial customers served by LDCs are insulated from day-to-day price volatility, through state or local regulation with periodic adjustments reflecting the average cost of gas purchased over a longer period. Ultimately consumers' bills reflect price level changes.

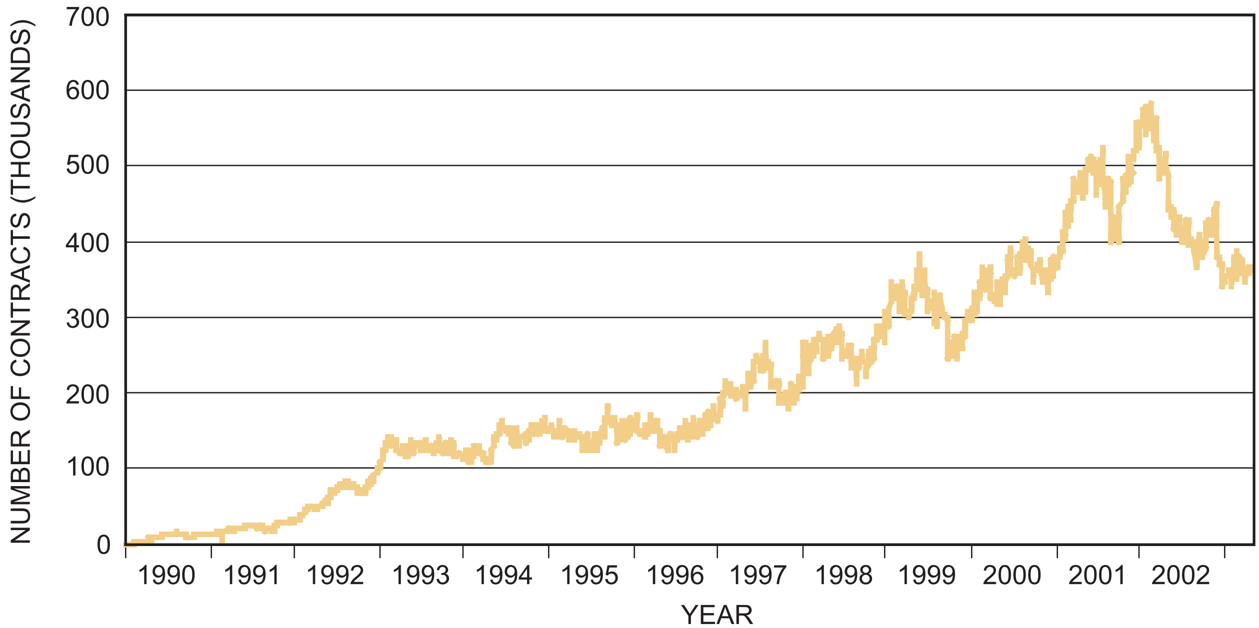
Industrial gas consumers tend to be more exposed to short-term price effects since they usually buy gas in the monthly and daily markets, and therefore have been most affected by rising prices (this also makes them the first to benefit from falling prices). Rising gas prices have caused some industrial plant shutdowns and relocations of some manufacturing to foreign locations with lower cost natural gas. Industries most affected are the fertilizer, methanol, steel and chemicals.

There are several steps that market participants and regulators can take to mitigate price volatility. These include: 1) contracting for firm transportation and storage; 2) switching to lower cost alternate fuels; 3) using financial hedges – a strategy that does not eliminate risk, but does create price certainty; 4) contracting under long-term fixed price agreements; and 5) making available timely and reliable information regarding supply, demand, and storage levels. Items 1-4 require a cost-to-benefit analysis to determine whether they should be adopted by individual market participants. Item 5 is best facilitated by government action.

Exposure to price volatility to a great extent is about choices that market participants make. Participants may choose to buy or sell in the short-term daily market and not contract for storage or transportation capacity – this exposes them to increased volatility. Others may choose to contract under long term arrangements for the purchase or sale of gas and hold firm transport capacity thereby reducing their exposure to price volatility. Additionally the futures market may be used to manage forward pricing. In summary, tools are available to help manage the risk of price volatility, but they come at a cost.

There have been major changes in gas market participants over the past two years. Several large marketing companies have exited the physical and financial gas trading business, and on-line trading operations have declined. The number of participants offering a broad portfolio of financial products has been reduced and the need to trade with credit-worthy entities has been reinforced. These changes have highlighted a potential decline in market depth (e.g., number of players) particularly for long-term hedges, and therefore have contributed to a reduction in some customers' ability to manage long-term price volatility.

The rise of financial products has been fairly dramatic since 1990. The trend in the use of NYMEX financial instruments is illustrated in Figure 46 and shows increasing open interest in NYMEX contracts through mid 2002. Open interest is a measure of activity on NYMEX and gives some indication of overall market depth and liquidity. Current levels of NYMEX trading at the Henry Hub are below the 2002 peak but above the overall range of the 1990s. Marketers have traditionally been the major market makers and counter parties for a broad suite of NYMEX and over-the-counter financial tools (price swaps, forward price options, basis swaps, etc.) in addition to physical gas volumes. There are now fewer marketing entities offering these comprehensive services as they now also have fewer parties to transact with and mitigate exposures.



Open Interest: The number of open or outstanding contracts for which an entity is obligated to the Exchange because that entity has not yet made an offsetting sale or purchase, an actual contract delivery.

FIGURE 46
NYMEX OPEN INTEREST – NATURAL GAS CONTRACTS

Despite the recent changes in market participants, overall liquidity remains sufficient for parties to transact at multiple physical trading hubs and to access effective financial markets. Although physical flows have remained relatively constant, liquidity at some locations other than the major hubs is reduced from that of recent years, and reported trading volumes have declined from recent peaks. Continued enhancement of market liquidity and expanded market depth remain goals for industry, and the market is adjusting as appropriate. Government should allow free-market forces to work, and markets will continue adjusting for an effective, efficient balance.

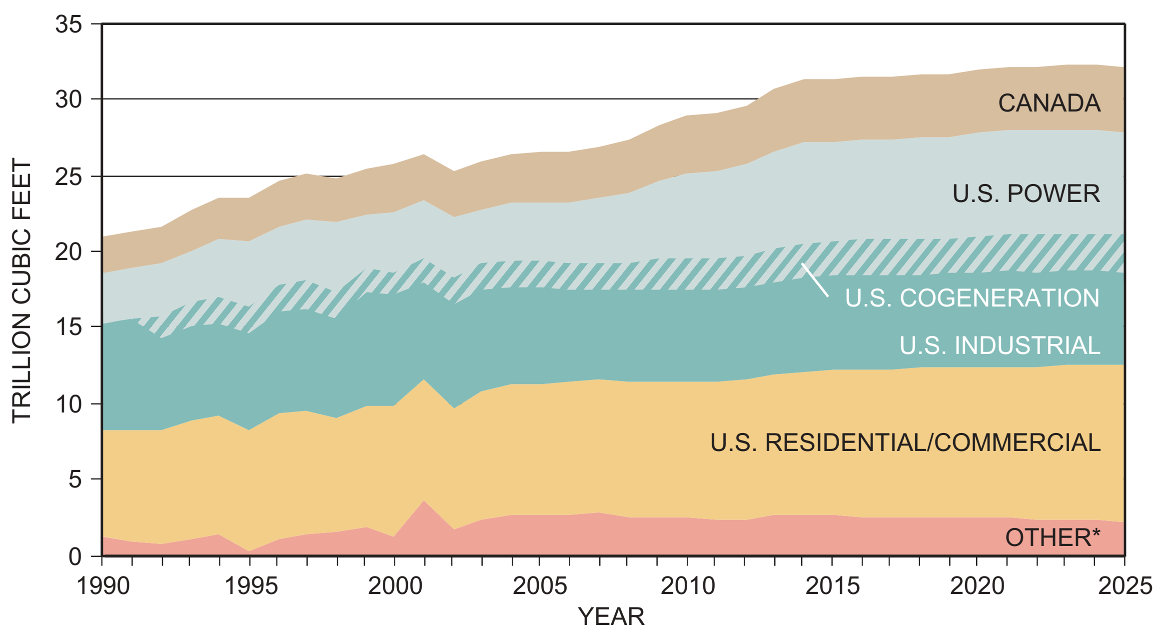
FINDING 11: A BALANCED FUTURE THAT INCLUDES INCREASED ENERGY EFFICIENCY, IMMEDIATE DEVELOPMENT OF NEW RESOURCES, AND FLEXIBILITY IN FUEL CHOICE COULD SAVE $1 TRILLION IN U.S. NATURAL GAS COSTS OVER THE NEXT 20 YEARS. PUBLIC POLICY MUST SUPPORT THESE OBJECTIVES.

Competitive markets are the most effective means to ensure that consumers get the greatest benefit from the use of our natural gas resource endowment. These benefits are significantly affected by policy choices at all levels of government. The most difficult task faced by the NPC was to assess the future balance of consumption and new supplies in the face of a tight market for natural gas. On the demand side, the ability and likelihood of consumers to switch to lower-cost fuels was comprehensively evaluated, as was the potential for more stringent environmental regulation – a course that could lead to an even greater demand for gas.

On the supply side, consideration was given to the uncertainties in estimating the size of the indigenous North American resource base, the rate of technology development, as well as regulatory actions that might accelerate or delay development of domestic and foreign sources of supply.

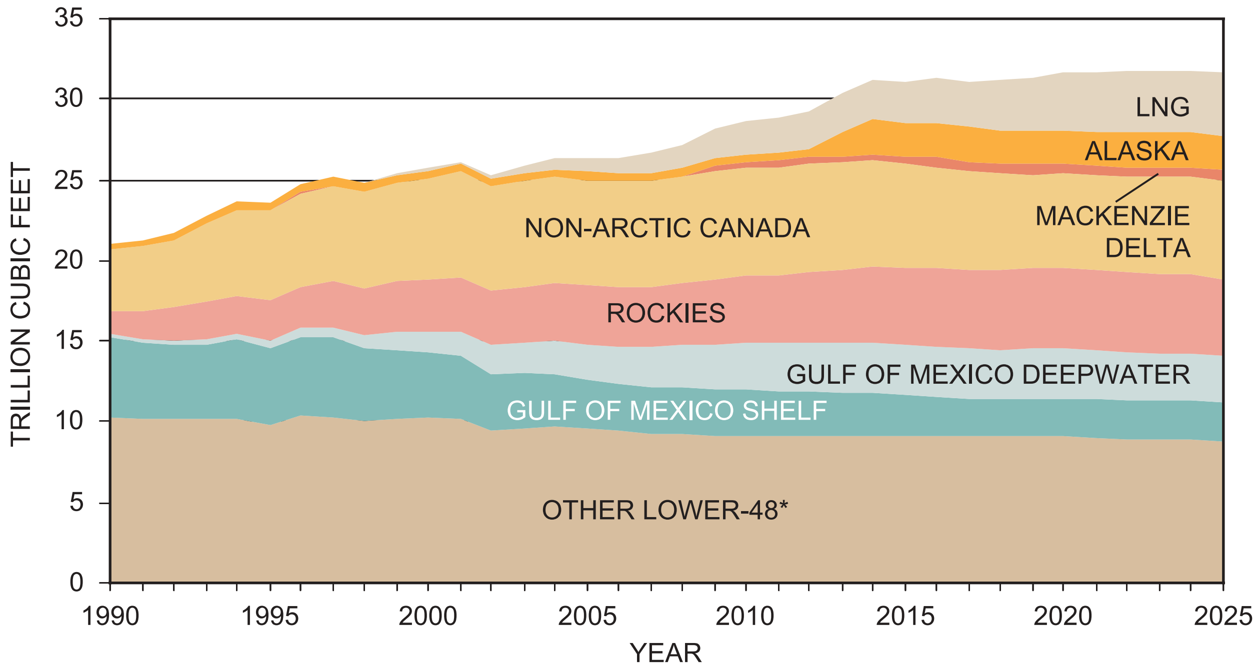
As previously described, two primary scenarios were used to evaluate the long-range outlook. The Reactive Path case was modeled based on existing environmental regulations and policies for both production and consumption of natural gas. This case continues the current limitations on fuel switching and the use of alternative fuels, as well as the restrictions to supplies, particularly in the Rocky Mountain region and offshore lower-48 states. Despite these limitations, the Reactive Path case assumes industry will be able to discover and develop significant new quantities of gas in the lower-48 states and Canada, import very large volumes of LNG, and commercialize Arctic gas in a timely manner. The Reactive Path case also assumes that there is no major new environmental law or initiative that significantly reduces the ability of coal, nuclear, and hydroelectric power to provide electricity.

Even with these potentially optimistic assumptions, the Reactive Path outlook still results in a very tight balance of supply and demand. Overall natural gas demand continues to grow largely as a result of strong new power generation needs. Industrial demand is lower in response to higher prices and the tight supply and demand balance. Increasing natural gas demand is met primarily with growing LNG imports and Arctic gas developments, while robust prices are required to maintain production levels from indigenous lower-48 and Canadian sources. After development of Arctic resources, the value of gas relative to alternate fuels continues to grow in the Reactive Path case, implying a structural change in price projections for natural gas. The demand and supply components for the Reactive Path case are shown in Figures 47 and 48. The price range outlooks for the Reactive Path and Balanced Future cases are shown in Figure 49.



* Includes net Mexico exports, lease/plant/pipeline fuel, and net storage.

FIGURE 47
U.S. AND CANADIAN NATURAL GAS DEMAND — REACTIVE PATH



* Includes lower-48 production, ethane rejection, and supplemental gas.

FIGURE 48
U.S. AND CANADIAN NATURAL GAS SUPPLY — REACTIVE PATH

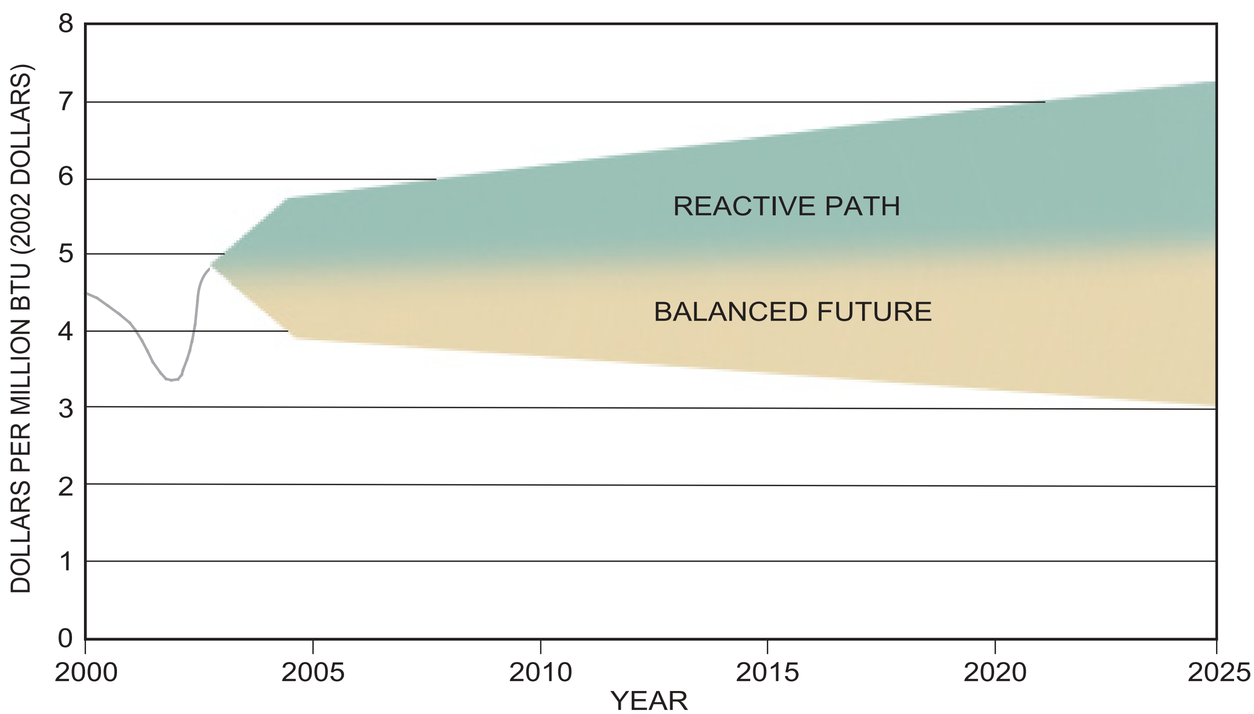


FIGURE 49
AVERAGE ANNUAL HENRY HUB PRICES

This outlook raises many questions and concerns. Many believe that market forces should better balance supply and demand, and that our inexperience with such a sustained high-price environment may be affecting our ability to model the response of supply and demand. For example, it is possible that such price signals could lead to periods of oversupply, as numerous high-volume, long-lead-time supply projects come on stream, potentially in an environment in which demand has been reduced by high prices. However, given the supply and demand assumptions inherent in the Reactive Path case, the NPC was unable to develop a credible case for such a balance without policy actions that encourage supply and give industrial consumers and power generators more options in their choice of fuel.

To evaluate these policy choices, the Balanced Future case was developed. This case incorporates government policies that encourage a more diverse but environmentally sound future fuel mix, and which would relieve some of the pressure placed on gas by existing regulations. As a result, this case increases renewable, coal, and oil generation capacity. This assumes a regulatory regime with respect to mercury that reduces retirements of coal-fired capacity, increases the output of existing nuclear facilities, and reduces retirement of existing oil/gas switchable capacity. Additionally, this case assumes a systematic re-introduction of fuel flexibility in both industrial and power generation applications; 25% of existing gas-fired capacity is retrofitted for oil backup, 25% of new gas-fired capacity includes oil backup capability, and industrial boilers return to the fuel-switching level of 28% by 2025. These assumptions incorporate control technologies to assure continued compliance with existing air quality regulations. Finally, this case assumes enhanced efficiencies in residential and commercial sectors due to enhanced building codes, smart controls, and efficient market mechanisms such as real-time pricing.

On the supply side, the Balanced Future case assumes that improvements will be made in permitting processes and access to resources, which allow an increased supply outlook to be achieved, both through indigenous production and more timely, increased LNG imports (an additional 2.5 BCF/D). Lower-cost domestic production is achieved through lifting of the OCS moratoria and by reducing the effect of access restrictions caused by restrictive conditions of approval in the Rocky Mountain area by 50% over a 5-year period. The net effect of these policy-related changes is to reduce the cost to consumers of providing similar quantities of gas. Figures 50, 51, and 49 show the demand, supply, and price range projections, respectively, for the Balanced Future case.

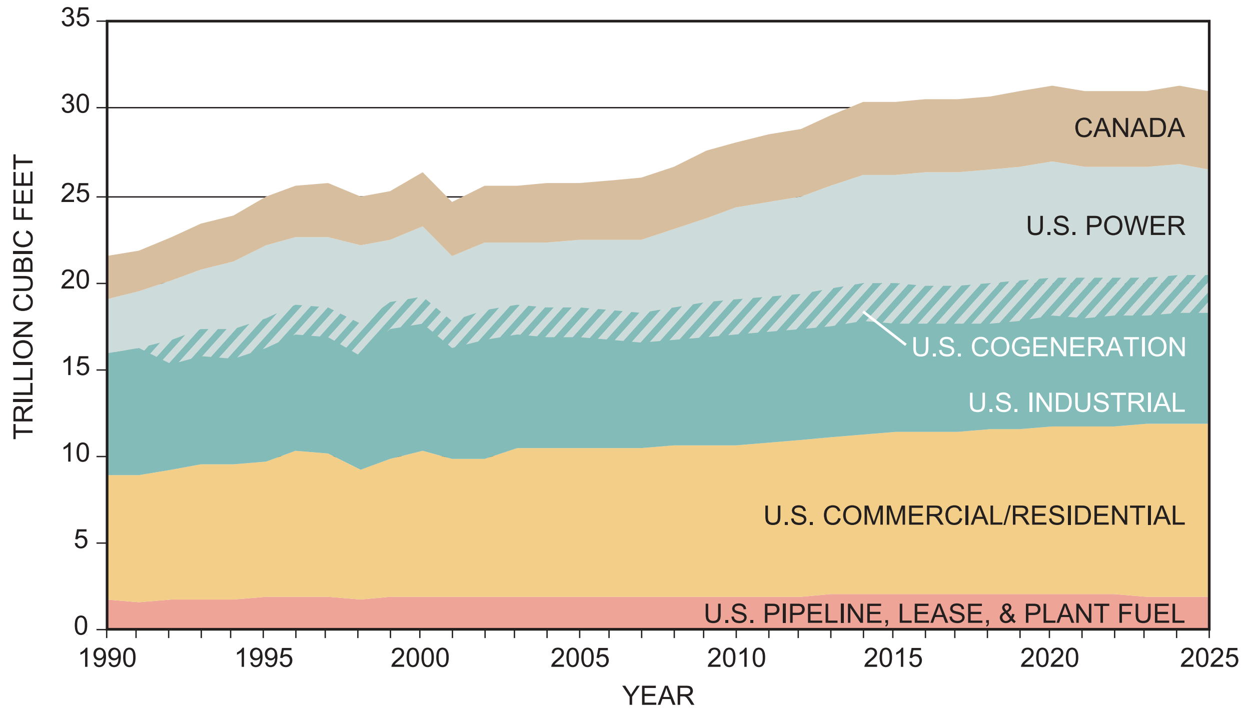


FIGURE 50
U.S. AND CANADIAN NATURAL GAS DEMAND — BALANCED FUTURE

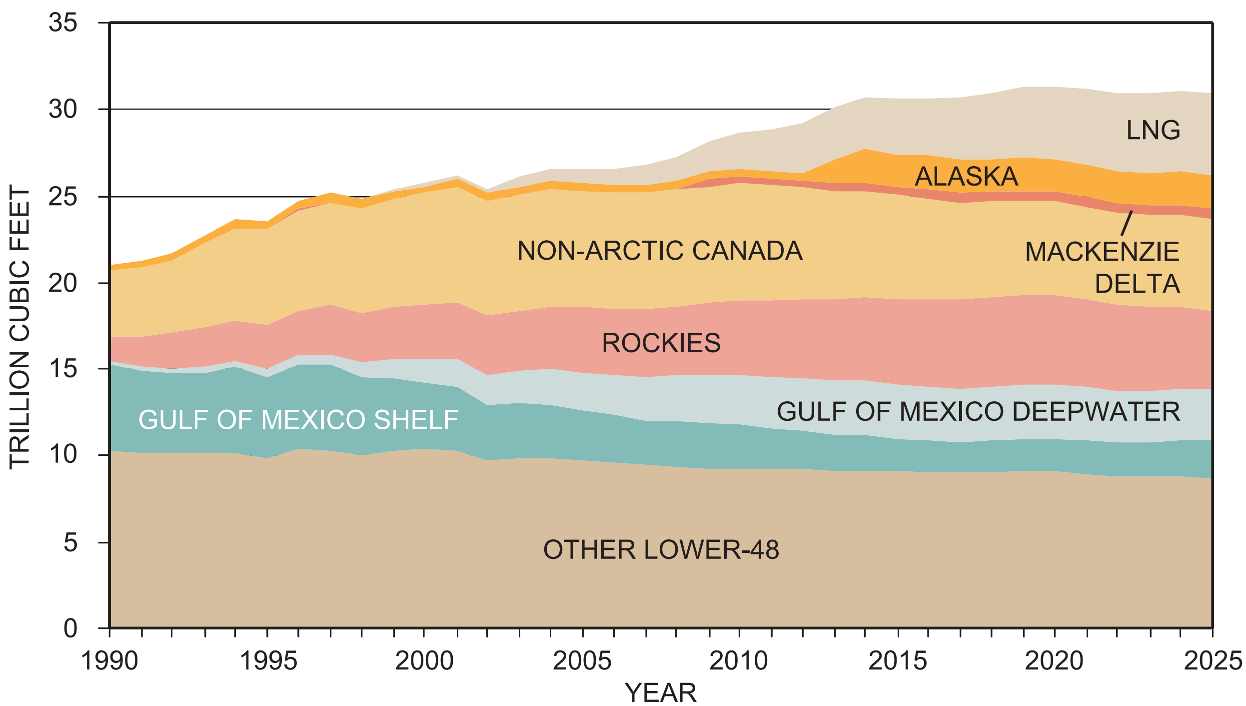


FIGURE 51
U.S. AND CANADIAN NATURAL GAS SUPPLY — BALANCED FUTURE

With lower cost supplies being made available, more demand can be satisfied, recognizing some demand being met by alternate fuels. It is particularly significant that more industrial demand for gas is satisfied in the Balanced Future case. Relatively small adjustments can make a big difference in achieving a comfortable supply/demand balance.

The NPC also evaluated cases that reflect even more difficult futures than the Reactive Path case, such as controls on carbon emissions and more limited access to gas resources. These evaluations are described in the Integrated Report. These assumptions clearly entail very high demand for gas, very tight supplies, and significant upward pressure on prices.

The NPC recognizes that this kind of analysis is sensitive to changes in assumptions. Any of a number of key variables – including economic growth, oil prices, resource base size, and technology development – can dramatically influence the outlook for future gas markets. Even recognizing those sensitivities, the fundamentals of the current situation are evident, especially for the next five years or so: indigenous supply is flat to declining, demand is growing, and there will be upward pressure on prices.

Capital Requirements

The NPC also evaluated the capital requirements of these outlooks. Almost $1.4 trillion (2002 dollars) in capital expenditures will be required to fund the U.S. and Canadian gas upstream and infrastructure industry from 2003 to 2025. Eighty-five percent will be spent in the exploration & production sector ($1.2 trillion) with the remaining 15% ($0.2 trillion) spent on pipelines, storage, and distribution, as can be shown in Figures 52 and 53. These expenditures represent a significant increase over the 1990-2000 period for the exploration & production sector. Expenditures for the pipeline, storage, and distribution sector are expected to remain relatively constant, considering increasing needs for “sustaining capital” to meet reliability requirements.

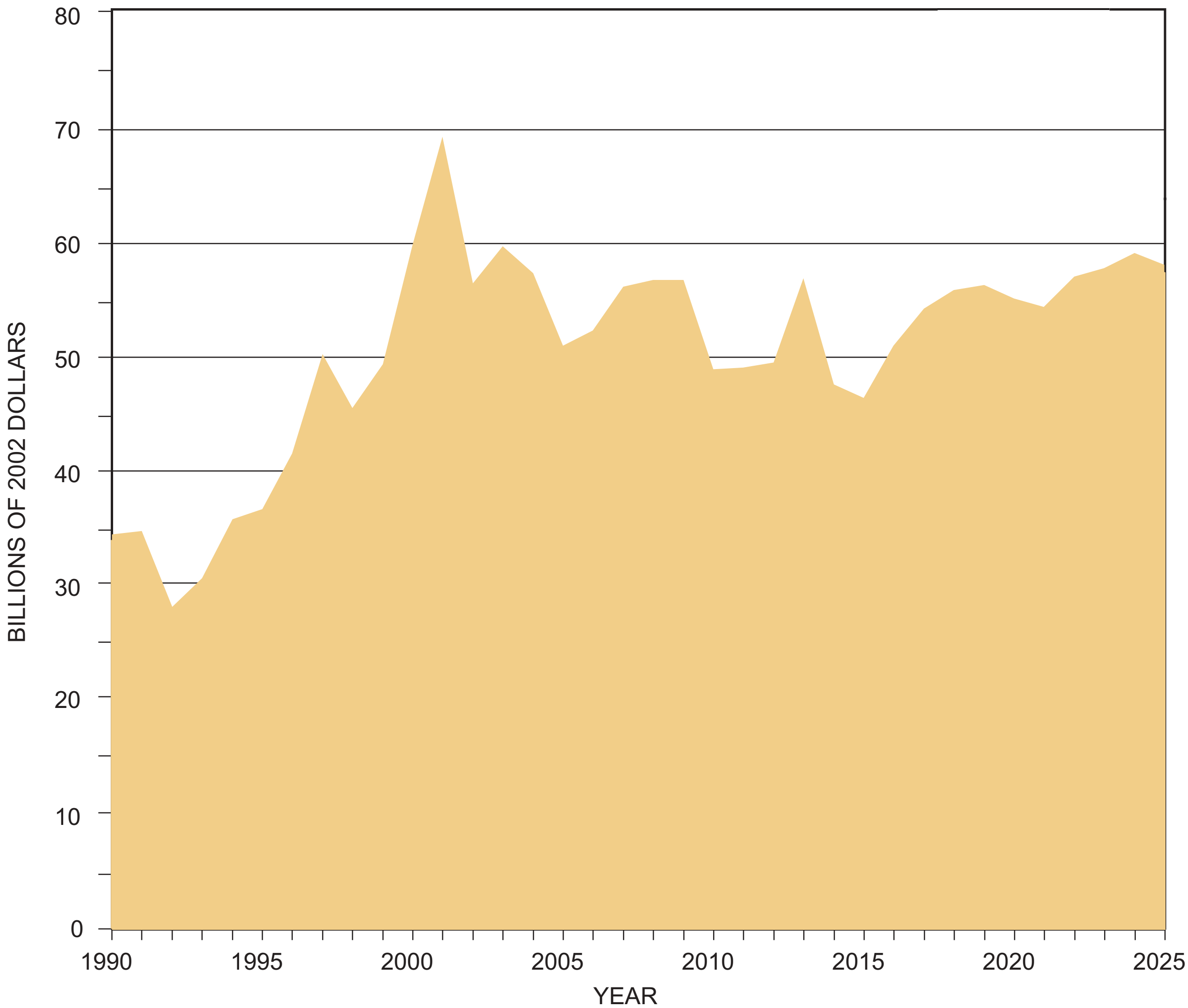


FIGURE 52
U.S. AND CANADIAN EXPLORATION AND PRODUCTION
CAPITAL EXPENDITURES — BALANCED FUTURE SCENARIO

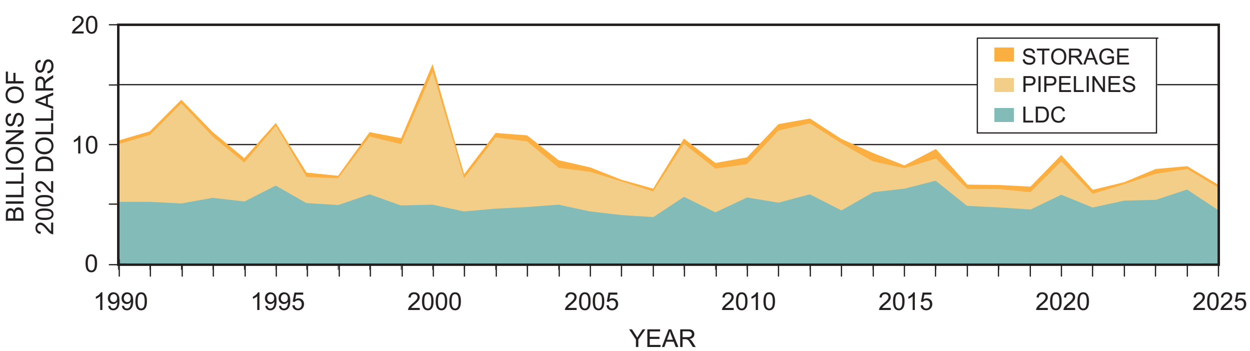


FIGURE 53
U.S. AND CANADIAN INFRASTRUCTURE
CAPITAL EXPENDITURES — BALANCED FUTURE SCENARIO

While a majority of the required capital will come from reinvested cash flow, industry will continue to need capital from the markets to fund the growth. To achieve this level of capital investment, industry must compete with other investment opportunities and deliver returns equal to or better than other S&P 500 companies. Some industry segments have not achieved this in the past and this presents a challenge for the future.

However, the capital spending envisioned in this outlook provides opportunity for a wide range of companies including small, private companies and large multinationals. Although there have been recent, notable bankruptcies and credit rating downgrades for companies linked to energy trading and merchant power activities, there is more than sufficient capital availability, liquidity and participation from credit-worthy companies to complete the projects with acceptable economic returns.

Clearly a broad spectrum of industries and consumers will be affected by the policy choices ahead. The NPC's recommendations on how to achieve a Balanced Future are listed in the section that follows.