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U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply

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Preface

On April 25, 2001, the Secretary of Energy, Spencer Abraham, asked the Energy Information Administration to conduct two studies of the North American natural gas market, in view of public concern about the "tight supplies, volatile prices, and regional price disparities" that were experienced during the winter of 2000-2001. The first study, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*, examined causes of the high prices during the winter of 2000-2001. It was released in May 2001. The study concluded that the high natural gas prices were caused by higher than normal demand, low natural gas prices in the preceding years that resulted in a scarcity of wellhead gas productive capacity relative to demand, and a low level of working gas in storage at the beginning of the 2000-2001 winter.

This study updates the first analysis, using more recent data on the U.S. natural gas market, and provides a more detailed examination of future market prospects. Secretary Abraham requested that four topics be considered in this study: (1) the impact of drilling on wellhead natural gas supply, (2) the potential for future imports of liquefied natural gas (LNG), (3) the impacts of removing limitations on access to Federal lands and offshore areas, and (4) an analysis of data improvements that would support a better understanding of natural gas markets. The questions addressed in the analysis are "What is the natural gas supply response to high natural gas prices?" "How do Federal access limitations constrain future supplies?" and "What role could LNG imports play in providing future gas supplies?"

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Recent Trends in Natural Gas Markets

Natural gas prices rose dramatically in 2000 and remained high through much of the first half of 2001. The sustained runup of prices was unprecedented in U.S. natural gas markets. Contributing to the price increases in 2000 were increased utilization of expanded natural gas consumption capacity, and a decline in natural gas productive capacity that limited production responses. Rising prices at the beginning of the natural gas storage refill season in April 2000 resulted in lower levels of injections than normal and unusually low levels of natural gas in storage at the start of the 2000-2001 winter. Exceptionally cold weather along with unusually low storage levels in November and December 2000 caused spot prices to spike higher, exceeding $10 per million British thermal units (Btu) on a few days in late December and early January 2001. These conditions have since abated with spot prices falling below $2 per million Btu on some days from late September to late November 2001.

As prices rose during 2000, the number of rotary rigs drilling for natural gas rose substantially, reaching 879 by year end, more than double the most recent low of 362 gas rigs in April 1999. The increase in drilling raised domestic production to 19.0 trillion cubic feet in 2000—an increase of almost 0.2 trillion cubic feet from 1999. At the same time, however, market demand expanded by more than 0.9 trillion cubic feet in 2000, absorbing all additional production and causing prices to rise.

The domestic natural gas production industry continued its expansion during 2001, with the number of active gas drilling rigs rising to 1,068 in mid-July 2001 and subsequently declining to 785 on November 30, 2001. Gas well completions in 2001 are expected to be more than 20,000 wells.[1] The large number of gas well completions increased effective productive capacity and resulted in a 6-percent increase in proved natural gas reserves between 1999 and 2000, by far the largest increase since the Energy Information Administration (EIA) began collecting these data in the late 1970s.[2]

Natural gas prices have declined substantially since early 2001, and supplies have been sufficient to allow record volumes to be added to storage—after ending the 2000-2001 heating season at 742 billion cubic feet, 16 billion cubic feet below the previous record end-of-season low. Net additions to working gas in storage during the 2001 refill season have occurred at a record pace. By November 1, working gas stocks are estimated to have reached more than 3,100 billion cubic feet. Even though the 2001 storage fill rate represents almost 4 billion cubic feet per day of incremental natural gas demand over refill rates in 2000, prices have fallen during this period—a clear indication that the supply situation has improved since last year. Increased productive capacity and slower growth in natural gas demand because of mild weather and a slowing economy have combined to reduce natural gas prices dramatically, despite an aggressive storage refill effort.

Canadian imports grew during 2000 primarily because of increased utilization of the Portland Pipeline and two new cross-border pipelines, the Maritimes & Northeast Pipeline (Maritimes) and the Alliance Pipeline. Maritimes became operational in January 2000, providing approximately 400 million cubic feet per day of capacity into eastern Massachusetts. The Alliance Pipeline, with a capacity of 1.3 billion cubic feet per day into the Chicago market, began operations in December 2000.

Natural gas imports from Canada have increased during 2001, and the new Alliance Pipeline has transported some of that increase. In April 2001, the Federal Energy Regulatory Commission (FERC) gave preliminary approval to Maritimes to extend its transportation capacity in 2002 by 350 million cubic feet per day.

Liquefied natural gas (LNG) imports grew during 2000, reaching 226 billion cubic feet, a 38-percent increase over the previous year. The imports came primarily from Algeria, Qatar, and Trinidad and Tobago.

California natural gas prices remained high through May 2001, as the local natural gas utilities and others injected as much gas into storage as possible. By the end of August, California had 187 billion cubic feet of

[1]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/11) (Washington, DC, November 2001). Estimate for 2001 based on 17,090 gas wells completed in the first 10 months of 2001.

[2]Energy Information Administration, *Advance Summary: Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 2000 Annual Report*, DOE/EIA-0216(2000)Advance Summary, p. 2, web site www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/advanced_summary_2000/adsum2000.pdf.

working gas in storage, 33 percent more than at the same time in 2000.[3] By November 30, 2001, with storage facilities full, California natural gas prices had declined to $2.19 per million Btu at the southern California border interconnect and $2.44 per million Btu at Pacific Gas and Electric's citygate.

Near-Term Outlook for Natural Gas Markets

The price reductions and record storage additions during 2001 indicate that the U.S. natural gas market contains the self-correcting mechanisms that are associated with well-functioning markets. This bodes well for the market outlook, as domestic resources are expected to be substantial and the potential exists for both Canadian and LNG supplies to expand, given favorable economics.

Natural gas prices are expected to continue to decline through next year.[4] Average monthly wellhead natural gas prices are expected to be $3.98 per million Btu in 2001, although prices have been decidedly lower in the latter part of the year than in the early months. Wellhead prices are projected to decline to $1.91 per million Btu in 2002, a 52-percent drop.

The lower price forecast for 2002 is based on current record-high storage volumes and the potential for record high additions to productive capacity. High storage levels are expected to moderate any upward price pressure, even if the 2001-2002 winter is colder than normal. If the winter weather is either normal or warmer than normal, there could be a significant surplus of natural gas storage supplies in the spring of 2002.

High natural gas prices during the second half of 2000 and the beginning of 2001 motivated a boom in gas well drilling that is expected to result in a significant increase in wellhead productive capacity. Although wellhead prices peaked in January 2001, the inherent delay between price changes and drilling increases meant that the gas drilling rig count did not peak until July 13, 2001, at 1,068 rigs. Depending on how quickly the gas rig count declines during the remainder of 2001, the annual average count could range between 910 and 924 rigs for 2001, which, in turn, could result in 2001 gas discoveries in the range of 22 to 24 trillion cubic feet. With new wellhead gas discoveries in 2000 replacing 99 percent of that year's natural gas production,[5] and with the prospect for even higher reserve discoveries in 2001, the large additions to wellhead natural gas supply during 2000 and 2001 create the potential for a further decline in wellhead natural gas prices. The potential for low natural gas prices during 2002 will be further enhanced if the domestic economy remains in recession, dampening natural gas demand from both industrial consumers and electricity generators, which together accounted for 60 percent of total natural gas consumption in 2000.

Although there were some regional pipeline capacity constraints, such as in California, during the winter of 2000-2001, overall pipeline capacity was adequate and appears to be so for the foreseeable future. The growth in demand for natural gas pipeline capacity appears to have peaked in some fast-growing market areas such as California, Florida, and New York, and the capacity constraints in these regions appear to be short-term in nature and readily resolved. In the first 9 months of 2001, 3.8 billion cubic feet per day of new capacity and 1,660 miles of pipeline were completed. If all remaining projects scheduled for completion during 2001 are actually finished, an additional 6.5 billion cubic feet per day of capacity will be added to the network.

Mid-Term Prospects for Natural Gas Supply

In light of the recent high natural gas prices, EIA conducted a mid-term model analysis, using the National Energy Modeling System (NEMS), of two natural gas supply options that could make more supplies available: removing access restrictions on Federal lands and the Outer Continental Shelf (OCS), and adding new LNG terminals. The reference case for the analysis was EIA's *Annual Energy Outlook 2002* (*AEO2002*) reference case.[6] In addition, a carbon dioxide emissions limit case was used to provide a baseline for comparisons in an environment of higher demand for natural gas.

The *AEO2002* reference case is a policy-neutral case developed by EIA under the assumption that all laws, including Federal access restrictions, remain in force as currently enacted. In the reference case, total dry natural gas production is projected to increase by 2.0 percent per year, from 19.1 trillion cubic feet in 2000 to 28.5 trillion

[3]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2001/10) (Washington, DC, October 2001), Table 14, p. 26.

[4]Projected values for 2001 and 2002 are from Energy Information Administration, *Short-Term Energy Outlook* (November 2001), web site www.eia.doe.gov/emeu/steo/pub/contents.html.

[5]Total natural gas reserve replacement for 2000 was 152 percent when new natural gas discoveries plus reserve adjustments, net reserve revisions, and net reserves from sales and acquisitions are considered. Only new wellhead gas discoveries are considered in this discussion, because the new reserves are a direct result of the natural gas found through drilling activity. In contrast, reserve revisions, for example, can represent the installation of recovery equipment, which was made more affordable by the high natural gas prices of 2000.

[6]Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), web site www.eia.doe.gov/oiaf/aeo/.

cubic feet in 2020. The natural gas wellhead price is projected to reach $3.26 per thousand cubic feet in 2020.

The carbon dioxide emissions limit case includes all the assumptions of the reference case, as well as a cap on carbon dioxide emissions from the electricity generation sector that results in higher demand for natural gas. Relative to the reference case, the carbon dioxide emissions limit case projects higher natural gas production in the lower 48 States from 2005 through 2015, which is later supplanted by natural gas supplies flowing from new LNG terminals and an Alaskan natural gas pipeline. By 2020, much of the incremental natural gas supply required in the carbon dioxide emissions limit case is projected to be met by Alaskan natural gas shipments to the lower 48 States (1.6 trillion cubic feet) and by higher net imports of LNG (almost 1.4 trillion cubic feet). Total dry natural gas production in 2020 is projected to be 30.2 trillion cubic feet. The lower 48 average wellhead natural gas price is projected to be $3.72 per thousand cubic feet in 2020 in the carbon dioxide emissions limit case.

Analysis of Access Restrictions on Federal Lands

Federal access restrictions substantially affect the Rocky Mountain region, where considerable natural gas resources are either off limits (legally or *de facto*[7]) to exploration and development or subject to Federal lease stipulations.[8] Federal access limitations also affect offshore natural gas resources in the Pacific, Atlantic, and Eastern Gulf of Mexico OCS. Except for a relatively small tract in the Eastern Gulf of Mexico, these areas are legally off limits to exploration and development under existing Federal moratoria.

Reducing Federal access restrictions in the Rocky Mountains and OCS is expected to increase the available resource base by 87 trillion cubic feet, which would expand the available lower 48 resource base from 1,190 to 1,277 trillion cubic feet, a 7-percent increase. Reducing Federal access restrictions does not imply that all land restrictions would be removed. An estimated 62.5 trillion cubic feet of natural gas resources would remain unavailable for development, for example, in National Parks, National Monuments, and wilderness and roadless areas, as well as areas currently precluded by the effect of statutes and regulations. Although the available resource base expands by 7 percent with increased Federal access, lower 48 production during the forecast increases only slightly, because production is driven by demand for natural gas. The primary impact of greater Federal access is to reduce natural gas prices slightly as a result of the availability of lower cost resources that were otherwise unavailable to the gas market. The slightly lower prices are projected to result in slightly higher demand for natural gas and, accordingly, slightly higher levels of natural gas production.

The Rocky Mountain region contains approximately 35 percent (293 trillion cubic feet) of the remaining unproved technically recoverable natural gas resources in the lower 48 onshore United States.[9,10] Most of the Rocky Mountain resources (81 percent) are "unconventional"—65 percent in low permeability sandstones (tight sands), 16 percent in coal formations (coalbed methane), and a negligible amount in low permeability shales (gas shales).

The 293.3 trillion cubic feet of unproved Rocky Mountain natural gas resources are subject to a variety of access restrictions. Of that amount, 33.6 trillion cubic feet is officially off limits to either drilling or surface occupancy. An additional 57.7 trillion cubic feet of the resources are judged to be currently *de facto* off limits because of the prohibitive effect of compliance with environmental and pipeline regulations. Of the 202 trillion cubic feet of resources that are accessible, 50.8 trillion cubic feet are located in areas where Federal lease stipulations are estimated to increase development costs by 6 percent and to add 2 years to their development schedule. The remaining 151.2 trillion cubic feet of unproved Rocky Mountain natural gas resources are located either on Federal land without lease stipulations or on private land and are fully accessible subject to standard lease terms (without lease stipulations).

Estimated total undiscovered,[11] technically recoverable natural gas resource as of January 1, 2000, in the entire lower 48 OCS is 233.7 trillion cubic feet. The currently inaccessible portion of the total amounts to 58.2 trillion cubic feet, with 18.9 trillion cubic feet in the Pacific, 28.0 trillion cubic feet in the Atlantic, and 11.3 trillion cubic feet in the Eastern Gulf of Mexico. The remaining 175.5 trillion cubic feet of fully accessible lower 48 OCS resources are located almost entirely in the Western and Central Gulf of Mexico, with 1 trillion cubic feet in the Eastern Gulf of Mexico.

EIA's analysis assumed that increased access to Federal lands would increase the exploitable resource base in the Rocky Mountains by 28.8 trillion cubic feet and would

[7]Resources judged to be off limits because of the prohibitive effect of compliance with environmental laws and regulations.

[8]Lease stipulations are mandated modifications to a lease.

[9]Unproved resources are those resources that are estimated to exist based on analyses of the size and characteristics of existing fields and the geologic basins in which they reside, but these resources have not been proven to exist through actual drilling.

[10]Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability. These resources are generally conceived as existing in accumulations of sufficient size to be amenable to the application of existing recovery technology.

[11]Undiscovered resources are unproved resources that are estimated to exist in fields that have yet to be discovered.

reduce development costs by 6 percent and development times by 2 years for an additional 50.8 trillion cubic feet of Rocky Mountain resources. In the OCS region, increased access was assumed to expand exploitable offshore resources by the full 58.2 trillion cubic feet that is currently inaccessible. It was also assumed that leases for currently restricted OCS areas would be included in a 2007-2012 lease sale. For both the Rocky Mountains and the OCS, resource development costs were assumed to be the same as those in unrestricted areas.

The impact of lifting Federal access restrictions was examined in four analysis cases:

- **Rocky Mountain access case:** Includes all the assumptions of the reference case, but reduces Federal access restrictions in the Rocky Mountain region.
- **OCS access case:** Includes all the assumptions of the reference case, but removes Federal access restrictions in currently inaccessible areas of the OCS.
- **Rocky Mountain and OCS access case:** Includes all the assumptions of the reference case, but reduces Federal access restrictions in the Rocky Mountain region and opens currently inaccessible areas of the OCS.
- **Rocky Mountain and OCS access case with carbon dioxide emissions limit**: Includes all the assumptions of the carbon dioxide emissions limit case, but reduces Federal access restrictions in the Rocky Mountain region and opens currently inaccessible areas of the OCS.

The projections for natural gas production and prices in 2020 are shown in Table ES1.

As shown in Table ES1, increasing access to restricted areas in either the Rocky Mountains or the OCS areas results in about the same magnitude of incremental production relative to the reference case, amounting to just under 250 billion cubic feet per year. Simultaneously increasing access to both the Rocky Mountain and OCS restricted areas provides slightly more incremental production than the sum of the two increments in the single access cases, amounting to about 580 billion cubic feet per year.

The Rocky Mountain and OCS access case with a carbon dioxide emissions limit indicates that the impact of increased Federal access would be more significant in an environment of high demand and high natural gas prices. This is because a substantial share of the newly accessible resource base, particularly in the offshore, requires higher prices to be profitable. In comparison with the carbon dioxide emissions limit case without increased access, projected natural gas production in 2020 is just over 1 trillion cubic feet per year higher. Collectively, the results suggest that the benefits of increased Federal access would be proportional to future demand for natural gas supplies, which in turn depends on other factors, such as economic growth and the availability and costs of other energy sources (coal, nuclear, and renewable energy).

Analysis of LNG Imports

LNG imports are expected to become a larger source of natural gas supply in the mid-term. The *AEO2002* reference case projects growth in net LNG imports from 0.2 trillion cubic feet in 2000 to 0.8 trillion cubic feet in 2010, leveling off at that amount through 2020. The reference case projection is based on the expectation that the four existing U.S. LNG terminals—Cove Point, Maryland; Elba Island, Georgia; Everett, Massachusetts; and Lake Charles, Louisiana—will operate at full capacity (80 percent of design capacity) by 2010.

LNG has become a more viable source of future natural gas supply because of the extent of world natural gas resources and the significant decline in LNG costs in all segments of the supply chain. As of January 1, 2001, 10 countries held 77 percent of the world's natural gas reserves (4,043 trillion cubic feet out of 5,278 trillion cubic feet), with Russia, Iran, and Qatar accounting for more than 55 percent (2,906 trillion cubic feet).[12] Given

Table ES1. Projected Natural Gas Production and Average Wellhead Prices in Six Cases, 2020

Analysis Case	Total Dry Natural Gas Production (Trillion Cubic Feet per Year)	Lower 48 Average Wellhead Natural Gas Price (2000 Dollars per Thousand Cubic Feet)
Reference	28.5	3.26
Carbon Dioxide Emissions Limit	30.2	3.72
Rocky Mountain Access	28.7	3.20
OCS Access	28.7	3.22
Rocky Mountain and OCS Access	29.1	3.15
Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	31.2	3.57

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, ACCRM.D111101A, ACCOFF.D111101A, ACCREF.D111101A, and ACCHDEM.D111101A.

[12] "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 98, No. 51 (December 18, 2000), pp. 121-124.

this concentration of resources and the need for countries to monetize resources, an increase in the quantity of natural gas traded across international borders is all but inevitable.

If sufficient domestic LNG processing capacity existed, LNG imports could play a potentially important role in the U.S. natural gas market by dampening natural gas price extremes. Increasing spot cargos of LNG during periods of high prices would moderate price increases, and reducing spot cargos during periods of low prices would moderate price declines.

Projected LNG costs in the reference case fall within the range of the recent high natural gas prices. Liquefaction costs between 1996 and 2000 averaged $230 per ton compared with $560 per ton between 1986 and 1990. Between 1996 and 2000 the cost of a new tanker dropped by approximately 30 percent.[13] The construction costs for regasification terminals have seen similar decreases. Because of the capital-intensive nature of LNG trade, more than 70 percent of the cost of regasified, delivered natural gas is made up of processing and transportation costs.

There is considerable uncertainty about the costs of constructing new LNG terminals, because the capital costs for any particular project are site-specific and can vary considerably, depending on the harbor's characteristics, land costs, access to interstate transmission systems, and the degree of local opposition to the project. Moreover, the future delivered cost of LNG to a terminal depends on the world LNG market, and there is a potential for the few large LNG producers to create a cartel similar to the Organization of Petroleum Exporting Countries (OPEC). Given this price uncertainty, EIA's analysis examined the impact of both high and low cost assumptions.

LNG already plays an expanding role in meeting natural gas demand in the reference case projections, with imports projected to grow from 160 billion cubic feet per year in 2000 to 830 billion cubic feet per year in 2020. The growth in imports is expected to come from increased utilization of existing domestic terminals, plus some expansion at existing sites. In the carbon dioxide emissions limit case (described above), with higher projected demand for natural gas in the lower 48 States, LNG imports increase even more, to 1,350 billion cubic feet.

To examine the effects of a range of LNG costs, cost assumptions were varied—within the context of the carbon emissions limit case—in two analysis cases:

- **High LNG cost case:** Includes all the assumptions of the carbon dioxide emissions limit case, but assumes higher LNG production costs and higher returns on investments in LNG tankers and liquefaction plants.
- **Low LNG cost case:** Includes all the assumptions of the carbon dioxide emissions limit case, but assumes lower LNG production costs and lower returns on investments in LNG tankers and liquefaction plants.

Table ES2 summarizes the projections for net LNG imports and natural gas wellhead prices in 2020.

Like increased Federal access, the potential contribution of increased LNG imports to future natural gas supplies depends in part on the level of demand for natural gas, as shown by the projections in the reference and carbon dioxide emissions limit cases, both of which are based on current LNG cost estimates. In addition, however, the future costs of LNG production and processing facilities are projected to affect its role in natural gas supply. In the high LNG cost case, which assumes higher costs (such as those that might result from an LNG producer cartel or from costly site permitting), net LNG imports in 2020 are projected to be lower than in the carbon dioxide emissions limit case, and natural gas wellhead prices are projected to be 7 cents per thousand cubic feet higher. In contrast, in the low LNG cost case, net LNG imports in 2020 increase to 1.74 trillion cubic feet per year, and the average wellhead natural gas price is 9 cents per thousand cubic feet lower.

Table ES2. Projected Net LNG Imports and Average Lower 48 Wellhead Natural Gas Prices in Four Cases, 2020

Analysis Case	Net LNG Imports (Trillion Cubic Feet per Year)	Lower 48 Average Wellhead Natural Gas Price (2000 Dollars per Thousand Cubic Feet)
Reference	0.83	3.26
Carbon Dioxide Emissions Limit	1.35	3.72
High LNG Cost with Carbon Dioxide Emissions Limit	0.83	3.79
Low LNG Cost with Carbon Dioxide Emissions Limit	1.74	3.63

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, HCSTHDEM.D111101A, and LCSTHDEM.D111101B.

[13] Statistics on LNG trade are from D. Bamber, ed., *Fundamentals of the Global LNG Industry* (London, UK: Petroleum Economist, Ltd., March 2001), p. 11.

Mid-Term Trends in Natural Gas Supply and Prices: Potential for Cyclic Price and Investment Behavior

The natural gas production industry possesses the causal attributes necessary for business cycle behavior:

- Relatively inelastic supply and demand in the short term, which can cause large fluctuations in price during periods of relative scarcity or abundance of supply
- Large fluctuations in producer cash flows, investments, and wellhead gas supplies, as a result of large price fluctuations
- Significant delays (approximately 6 to 18 months) between changes in price and changes in wellhead gas supply, which encourage overinvestment when prices are high and underinvestment when prices are low, relative to gas demand
- Rapid declines in production from new natural gas wells, which could rapidly turn a supply surplus into a deficit during a period of low producer investment.

Short-Term Inelasticity of Natural Gas Supply and Demand

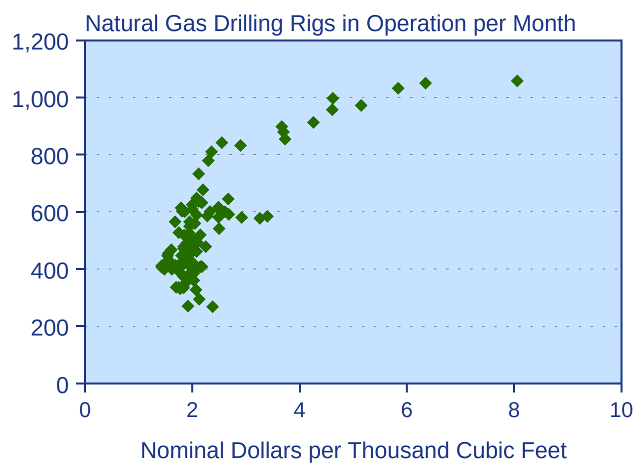
From early 2000 through mid-2001, a scarcity of available natural gas supplies led to sustained high wellhead prices for natural gas for the first time since the early 1980s. These sustained, high natural gas prices reflected the relative inflexibility of short-term natural gas production, in that natural gas drilling—and ultimately natural gas production—could not respond immediately to the high prices. Natural gas supply is also inelastic, because the U.S. natural gas market is relatively isolated from overseas natural gas supplies due to a limited LNG import infrastructure and the limited extent of LNG international trade.

Natural gas consumption is also relatively inelastic to prices in the short term, because natural gas consumption equipment typically has lifetimes in excess of 15 years. The short-term inelasticity of natural gas demand increases the probability that natural gas supplies could be either comparatively abundant or scarce relative to prevailing natural gas consumption requirements. Short-term supply and demand inelasticity could lead to wide swings in future natural gas prices.

Dependence of New Productive Capacity on Producer Cash Flows and Prices

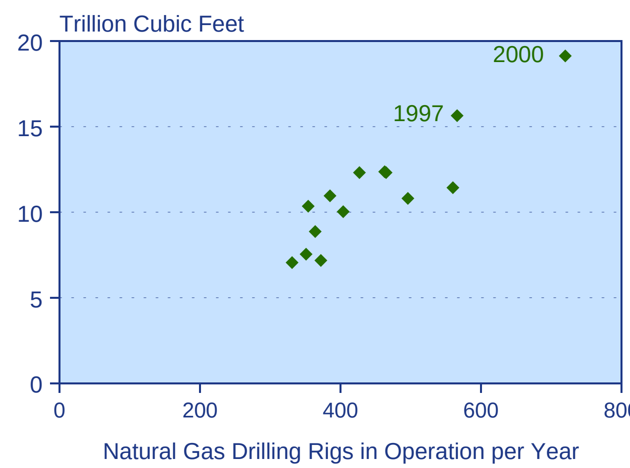
The development of new wellhead natural gas supplies is dependent on natural gas prices. When prices are high, producer cash flows are also high, inducing investment and drilling (Figure ES1). Natural gas drilling activity, in turn, is directly related to the development of new productive capacity, with higher gas rig levels generally resulting in a higher level of natural gas discoveries (Figure ES2).[14] As a rule, high natural gas prices result in high levels of new natural gas productive capacity, and low natural gas prices result in low levels of new natural gas productive capacity.

Figure ES1. Scatter Plot of Monthly Natural Gas Drilling Rigs Versus Wellhead Natural Gas Prices 6 Months Earlier, July 1992 - September 2001



Sources: See Chapter 4, page 44, footnote 94.

Figure ES2. New Natural Gas Discoveries as a Function of Average Annual Natural Gas Drilling Rigs, 1987-2000



Sources: See Chapter 4, page 44, footnote 95.

[14] The correlation coefficient of these two data series is 0.898. However, the relatively low number of data points limits the ability to make an inference from this statistic.

Delays Between Price Changes and Drilling Investments

New wellhead natural gas supplies will increase or decrease as wellhead prices increase or decrease, but the response is not immediate. The delay between a price increase and a natural gas production increase may range between 6 and 18 months. In addition, there is a delay between the onset of a decline in natural gas prices and a reduction in drilling activity by producers, which appears to be about 7 months (Figure ES3). The delay between changes in price and changes in new wellhead supplies increases the propensity of natural gas producers to overinvest in new productive capacity during periods of high wellhead prices and to underinvest in new productive capacity during periods of low wellhead prices.

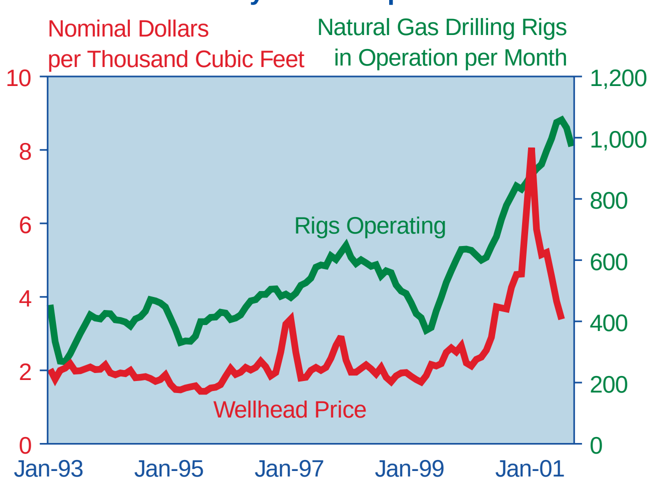
More Rapid Declines in Production From New Natural Gas Wells

In recent years, production from new natural gas wells has been declining more rapidly than in the past (Figure ES4).[15] Although there is some year-to-year variation in the trend, lower 48 gas well half-lives have declined from 40 months in 1990 to 24 months in 1999. The more rapid decline in natural gas well production rates increases the requirement for investment in new wells in the next year and the year beyond. If natural gas well drilling were to stop completely, productive capacity in the lower 48 States would decline by between 14 and 22 percent after 1 year and between 26 and 39 percent after 2 years.[16]

Low wellhead natural gas prices over any sustained period of time will reduce producer cash flow and could cause natural gas drilling to decline sufficiently to cause productive capacity to be less than the potential natural gas demand within a period as short as 1 year. Thus, low prices, low cash flows, and low investment levels increase the probability that natural gas supplies will fall quickly and cause a deficit in wellhead productive capacity relative to natural gas demand.

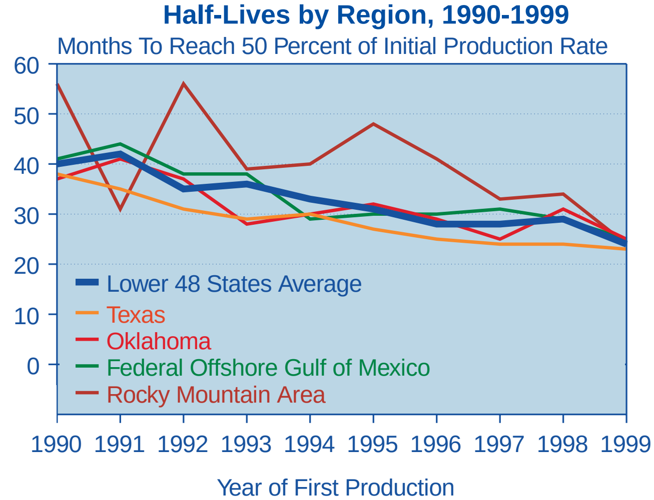
In summary, because neither productive capacity nor consumption is highly elastic with respect to price in the short term, a relative scarcity in wellhead productive capacity could be expected to cause very high natural gas prices, and a relative surplus could be expected to cause very low prices. When supply is scarce and prices are high, the delay associated with new natural gas supply investment would tend to cause natural gas prices to overshoot the long-run market-clearing wellhead price, contributing to the tendency for natural gas productive capacity to overshoot demand. As a result, the production "boom" would be followed by an extended period of low prices, insufficient investment, and rapidly declining natural gas productive capacity. Eventually, natural gas prices would begin to rise again as supply scarcity increased; however, the delay in new supply investments would cause prices to overshoot the long-run marginal cost and cause an over-investment in new productive capacity. Consequently, the natural gas industry embodies a set of dynamics that could cause periodic cycles in investment, drilling, supply, and prices. In the future, U.S. natural gas markets probably

Figure ES3. Average Monthly Natural Gas Wellhead Prices and Drilling Rigs, January 1993 - September 2001



Sources: See Chapter 4, page 44, footnote 94.

Figure ES4. Natural Gas Well Production Half-Lives by Region, 1990-1999



Source: Energy Information Administration, Office of OIl and Gas, Reserves and Production Division.

[15]The production half-life represents the amount of time that passes before a well (or a group of wells) produces natural gas at 50 percent of its (their) initial production level. The production rate half-life has declined for a host of reasons, including improvements in production technology and higher utilization of productive capacity.

[16]Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

will exhibit a tendency toward cyclic supply behavior, which may be either exacerbated or moderated by random external events, resulting in rather large and unpredictable price swings.

Implications of Large, Unpredictable Price Fluctuations

Large, unpredictable price fluctuations impose substantial risk on large, capital-intensive supply projects that require long lead times, such as LNG terminals and the Alaskan gas pipeline to the lower 48 States. In contrast, onshore, conventional drilling investments carry considerably less price risk, because they can be deployed more quickly and are shorter lived and therefore can take advantage of the immediate price environment. As a result, a price environment with large and unpredictable price swings would shift the mix of natural gas supply investments away from LNG terminals and the Alaskan pipeline toward conventional, onshore wellhead natural gas supplies. Ironically, LNG facilities might be precluded even though they could potentially moderate natural gas price extremes in the future by providing more natural gas during periods of high prices and less natural gas during periods of low prices.

Unpredictable prices also have deleterious consequences for natural gas consumers by increasing the risk associated with the operating costs of long-lived natural gas consumption facilities. For example, they obscure the value of appliances with higher energy efficiency ratings and can affect the financial viability of large industrial projects, such as electricity generation plants and fertilizer plants, where natural gas supply is the largest component of operating costs. Coal-fired projects might become more financially attractive than natural-gas-fired projects, simply because coal prices are expected to be more predictable and less likely to exhibit extreme fluctuations.

The deleterious effects of cyclical prices on suppliers and consumers can be mitigated through fixed-price contracts, price hedging and constant payment programs offered to residential consumers by local natural gas distributors. Although they are generally limited in duration, such financial instruments can mitigate the near-term financial impacts of unpredictable price behavior.

The Need for Improved Data on Natural Gas

The accuracy, timeliness, and detail of data series and products are important in providing adequate information for market analyses and policy decisions. Restructuring and growth in the industry, which began during the mid-1980s, expanded the number of market participants and changed business practices, requiring the design of new data collection instruments, increased efforts to identify industry participants, and greater effort by EIA and industry to assure data quality. In addition, greater data timeliness is desirable, which means that reliance on voluntary surveys and outside data sources such as those used for production data, wellhead price data, and imports data must be reviewed. Some data elements that have only been collected annually may need to be collected more often.

Consumption and Price Data

The collection of natural gas consumption data has been affected by the continuing restructuring of the natural gas and electricity generation industries, which started in the mid-1980s and mid-1990s, respectively. Industry changes have increased the difficulty of measuring total gas use accurately and assigning it to the appropriate sector—residential, commercial, industrial, transportation, or electricity generation, because firms providing natural gas delivery do not know the intended use for delivered natural gas.

Changes in the natural gas industry have had significant effects on data quality. The industry has grown and restructured in recent years as it moved away from its prior, more regulated structure. The types of information previously created for regulatory requirements and thus easily available for reporting to EIA are no longer available. There have also been large numbers of new firms, business sales, reorganizations, and mergers during this period.

For price data, as for volume data, the fact that pipeline and local distribution companies no longer know the purchasers and purchase terms for large volumes of natural gas sold means that data collected from them is less representative for measuring the average price of all final deliveries. For example, EIA's industrial end-use price data currently capture less than 20 percent of the total market. Because these prices primarily represent small industrial customers, it is likely that the reported sector prices are higher than the actual average industrial price.

Supply Data

Due to the large cost of collecting and processing data from many thousands of natural gas producers, the annual and monthly measurement of marketed natural gas production is based on voluntary annual and monthly reports by producing States and by the Minerals Management Service (MMS) of the U.S. Department of Interior. The States and MMS process the information for revenue purposes, but the resulting reported sales volumes do not necessarily represent the same production definitions requested by EIA. This frequently means that the elements used to calculate marketed production must be estimated by EIA.

While EIA requests information on the volume and value of marketed natural gas production, the States and MMS do not always use this point in the supply chain for their valuation. Given these differences regarding the value of natural gas for tax and royalty purposes, as well as the treatment of monetary elements such as taxes and other fees, EIA makes adjustments to reach a common definition across States. In addition, because data are not provided for most States until months after the requested report date, EIA uses an estimation procedure for U.S. average wellhead prices until complete data reports are received from the States.

Data on natural gas in underground storage are collected each month on a storage field and reservoir basis. Storage levels are then published on a State basis. These monthly data are subsequently adjusted to correspond to annual data. Weekly storage data are most useful for monitoring the potential for price volatility. In October 2001, Secretary of Energy Spencer Abraham directed EIA to begin a weekly gas storage survey in May 2002 after the American Gas Association announced its intent to discontinue its weekly survey of natural gas storage, which it has conducted since 1994.

As part of the triennial review of EIA's natural gas data collection authority, which must be conducted in 2002, EIA will invite suggestions and comment on many of the data issues discussed in this report. During the spring of 2002, EIA will release a *Federal Register* notice outlining a number of proposals developed as the result of interviews with data respondents and users and other reviews of the program. Following public comment, EIA will propose changes to the Office of Management and Budget. Authorized changes will be implemented during 2003.

1. Recent Trends in U.S. Natural Gas Markets

Background

Natural gas prices rose dramatically in 2000 and remained high through much of the first half of 2001. The sustained runup of prices was unprecedented in U.S. natural gas markets. Contributing to the price increases in 2000 were an increase in natural gas consumption and a decline in the productive capacity of the U.S. natural gas industry, which limited production responses. Rising prices at the beginning of the natural gas storage refill season in April 2000 resulted in lower levels of injections than normal and unusually low levels of natural gas in storage at the start of the 2000-2001 winter. Exceptionally cold weather in November and December 2000 caused spot prices to spike higher, exceeding $10 per million Btu[1] on a few days in late December and early January 2001.

From late September to late November 2001, spot market prices for natural gas have fallen below $2 per million Btu on some days, and prospects for consumers in the 2001-2002 winter are much improved over last year. There is still, however, significant public interest in the outlook for natural gas prices and supplies in the longer term. This chapter summarizes the trends, conditions, and market interactions that led to the recent cycle of severe price changes.

Overview

Prices in U.S. natural gas markets were relatively stable in the 1990s. The average monthly wellhead price in the lower 48 States in 1995-1999 was $1.98 per million Btu within a range of $1.39 to $3.31.[2] Since 1999, however, the price trends have changed dramatically. From January 2000 to June 2001, the mean price was $4.16 per million Btu within a range of $2.53 to $7.85. Daily spot prices showed a similar pattern with an even greater overall variability. For example, spot prices at the Henry Hub peaked at $10.52 per million Btu on December 29, 2000. Although quite high, this price is not the highest ever reported at that location. The price reached $14.50 on February 2, 1996, when an unexpected cold spell hit just before a weekend.[3]

The most striking aspect of the recent price pattern is the fact that prices were sustained at such high levels. It was the duration of high prices, more than the level itself, that was extraordinary. As a barometer of the markets, the sustained price surge of 2000 raised concerns as to whether the circumstances behind the price increases were transitory or were part of a shift in fundamental aspects of the market.

Natural gas markets have been subject to regulatory restructuring at the Federal level since 1978, when the Natural Gas Policy Act liberalized the existing price ceilings on gas produced for interstate commerce. Subsequent Federal legislative and regulatory actions dealt with removing the remaining price ceilings on all production for interstate commerce and transferring the ownership of interstate pipelines from companies that bought, transported, stored, and sold natural gas to open-access transporters that would provide only transportation services.[4]

The conversion of interstate pipeline companies to open-access transporters altered the nature of those companies and caused a change in the structure of both the upstream and downstream markets. As open-access transporters, the pipeline companies became intermediaries that served as a bridge between a vast population of buyers and sellers within and among the markets. The change also opened up opportunities for new roles for existing suppliers and created the possibility of entirely new companies, such as gas marketers.

[1]Natural gas prices in this chapter are reported in dollars per million British thermal units (Btu). Prices originally reported in dollars per thousand cubic feet were converted using the following heat content factors (Btu per cubic foot): U.S. natural gas, 1,027; Canadian imports, 1,019; Mexican imports, 1,000; and LNG imports, 1,090. Sources: Average U.S. factor for both overall production and consumption as reported in Energy Information Administration, *Annual Energy Review 2000*, EIA / DOE-0384(2000) (Washington, DC, August 2001), web site www.eia.doe.gov / aer / index2000.htm. All import factors represent the averages for 1999 and 2000 as reported in Energy Information Administration, "U.S. Natural Gas Imports and Exports—2000," *Natural Gas Monthly*, EIA / DOE-0130(2001 / 08) (Washington, DC, August 2001).

[2]Prices in nominal dollars unless otherwise noted.

[3]Spot prices from *Natural Gas Intelligence: Daily Gas Price Index*. Quoted spot prices are the average of the reported prices.

[4]Corporations that own and operate interstate natural gas pipeline companies often have subsidiaries that engage in other supply activities, but they are separate enterprises required to operate "at arm's length" from the pipeline transportation unit. Pipelines still provide storage services on behalf of others in some cases. Pipeline systems often include storage as an integral part of operations for balancing purposes, and capacity beyond a pipeline's operational requirements is made available for other customers.

Regulatory restructuring of the natural gas market at the Federal level generally has been viewed as successful. Transmission costs for interstate pipeline companies have declined,[5] and prices at all levels from the wellhead to the burner tip have been lower on average (Figure 1). These results have led some States to move toward a similar system for local distribution operations, in which local distribution companies (LDCs) would operate as open-access transporters and companies such as marketers would compete for retail sales. A number of States have already implemented comprehensive or partial restructuring of retail markets.[6]

Natural Gas Demand

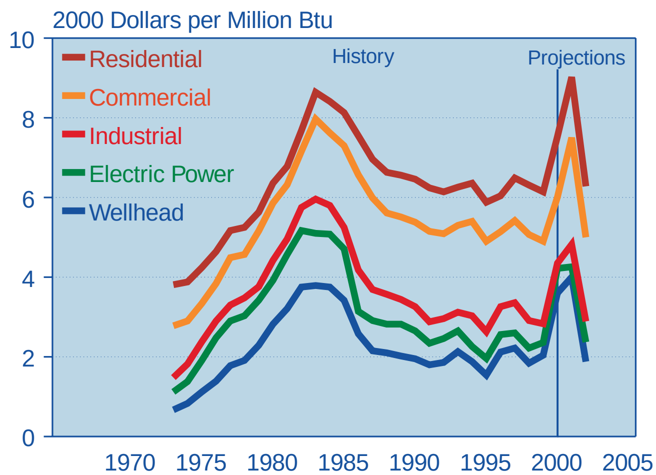
In the late 1990s, the potential capability to consume natural gas expanded considerably, mainly as a result of construction of new housing heated with natural gas and new electricity generation capacity fired with natural gas. Natural gas consumption did not increase as much as might have been expected, however, because of unusually mild winters and the price competitiveness of other fuels. Total end-use consumption of natural gas increased at an average rate of 0.5 percent per year, from 19.8 trillion cubic feet in 1995 to 20.2 trillion cubic feet in 1999,[7] with the greatest growth (3.3 percent per year) occurring in the electricity generation sector.[8]

When conditions (particularly the weather) changed in 2000, demand surged rapidly. Between 1999 and 2000, end-use consumption of natural gas increased by 3.8 percent to 20.9 trillion cubic feet (Figure 2). Natural gas consumption for electricity generation grew by 12 percent to 4.2 trillion cubic feet, accounting for 20 percent of end-use consumption. Natural gas consumption also grew substantially in the residential and commercial sectors, increasing by 5.8 percent and 7.3 percent, respectively, to 5.0 trillion cubic feet and 3.3 trillion cubic feet. Together, the residential and commercial sectors represented 40 percent of end-use natural gas consumption in 2000. Natural gas use in the industrial sector (including cogeneration of electricity), which declined by 2.2 percent to 8.4 trillion cubic feet in 2000, accounted for the other 40 percent of total end-use consumption.

Effects of Economic Growth

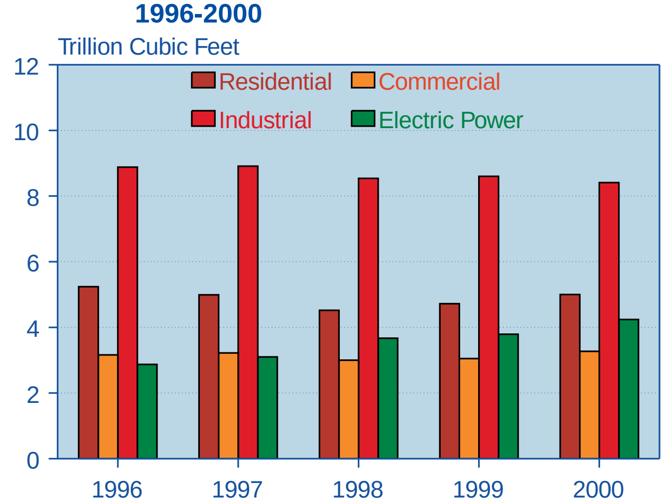
Strong economic growth during the 1990s boosted housing sales and new home construction. From 1991 to 1999, two-thirds of the new homes and 57 percent of the new multifamily buildings constructed were heated with natural gas (Figures 3 and 4). As the decade progressed, the share of gas-heated new homes increased from 60 to 70 percent, reaching 909,000 new units in 1999.[9] Estimates for 2000 show the share of new natural-gas-heated

Figure 1. Natural Gas Prices, 1973-2002



Source: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130, Table 4 (various issues); and *Short-Term Energy Outlook*, Table A4 (November 2001).

Figure 2. Natural Gas Deliveries to End Users, 1996-2000



Source: Energy Information Administration, supporting tables for *Annual Energy Outlook 2002*, DOE/EIA-0383 (2002) (Washington, DC, December 2001), Appendix A, Table A13 (2000 data estimated)..

[5]Energy Information Administration, *Natural Gas 1996: Issues and Trends*, DOE/EIA-0560(96) (Washington, DC, December 1996), Figure 8, p. 16.

[6]Energy Information Administration, "Status of Natural Gas Residential Choice Programs by State," web site www.eia.doe.gov/oil_gas/natural_gas/restructure/restructure.html.

[7]Annual natural gas volumes in this section are from EIA's *Annual Energy Outlook 2002*, in order to present consumption data including utility and nonutility power generation use on a consistent basis.

[8]Included in this category are electric utility companies and independent power producers. Not included are cogeneration facilities that produce electricity and another form of useful thermal output (such as heat or steam) for industrial applications.

[9]U.S. Department of Housing and Urban Development and U.S. Department of Commerce, *Characteristics of New Housing*, C25, Table 10 (various issues).

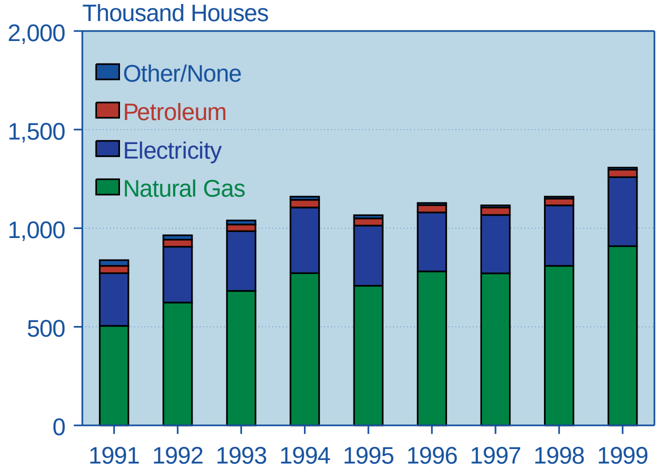
homes continuing to edge higher.[10] Although many new homes have more efficient furnaces, they also tend to be larger. As a result, the potential for increased consumption has grown, setting the stage for significantly higher consumption during colder weather, as happened in 2000.

There were similar increases in natural gas use in the commercial sector. The number of commercial gas customers increased from 4.6 million in 1995 to 5.1 million in 2000, while consumption rose by 6 percent.[11] More natural-gas-fired cogeneration capacity has also been built in the commercial sector since 1995, adding to potential demand. In 2000, the commercial sector accounted for 16 percent of natural gas consumption.

Parallel to the gradual transformation in the residential and commercial sectors, the electricity generation sector added new gas-fired generation capacity, dwarfing gains made by the other traditional generating fuels (Table 1). Between 1995 and 1999, 30.2 gigawatts of natural gas capacity was added, an increase of 18.5 percent. Overall, however, summer electricity generation capacity increased by only 21.1 gigawatts (2.8 percent) as 13.8 gigawatts of oil-fired generating capacity was taken out of service.

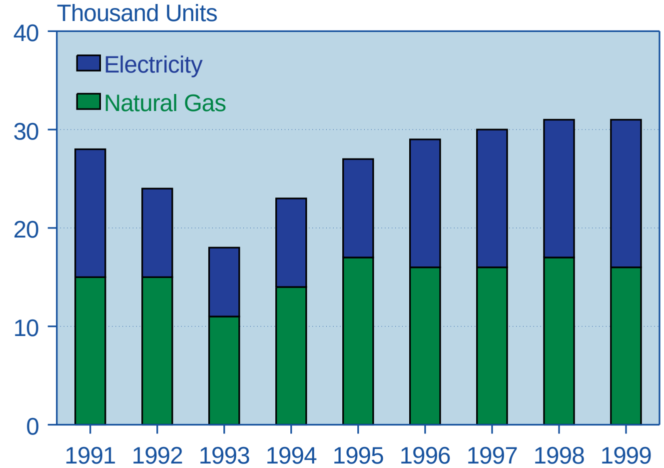
The expanding economy of the 1990s particularly affected manufacturing output, for which natural gas is a major fuel source. According to EIA's most recent Manufacturing Energy Consumption Survey, general

Figure 3. New Houses by Heating Fuel Type, 1991-1999



Source: U.S. Department of Housing and Urban Development and U.S. Department of Commerce, *Characteristics of New Housing,* C25, Table 10 (various issues).

Figure 4. New Multifamily Buildings by Heating Fuel Type, 1991-1999



Source: U.S. Department of Housing and Urban Development and U.S. Department of Commerce, *Characteristics of New Housing,* C25, Table 17 (various issues).

Table 1. Existing Capacity at U.S. Electricity Generation Facilities by Energy Source as of January 1, 1995-1999
(Megawatts Net Summer Capability)

Year	Coal	Natural Gas	Nuclear	Petroleum	Other	Total
1995	306,086	163,084	99,515	65,340	108,703	742,729
1996	308,098	162,617	100,784	71,245	105,849	748,593
1997	308,599	163,990	99,716	70,863	107,441	750,609
1998	308,906	170,052	97,070	64,350	108,306	748,685
1999	310,607	193,265	97,557	51,585	110,830	763,844

Notes: Electricity generation facilities include electric utility companies and independent power producers. Not included are cogeneration facilities that produce electricity and another form of thermal output (such as heat or steam) for industrial applications. Petroleum includes No. 2 fuel oil and No. 6 fuel oil. Other includes hydroelectric power.

Source: Derived from Energy Information Administration, Form EIA-860A, "Annual Electric Generator Report—Utility," and Form EIA-860B, "Annual Electric Generator Report—Nonutility."

[10] Energy Information Administration, *Annual Energy Outlook 2001,* DOE/EIA-0383(2001) (Washington DC, December 2000), Supplemental Table 21.

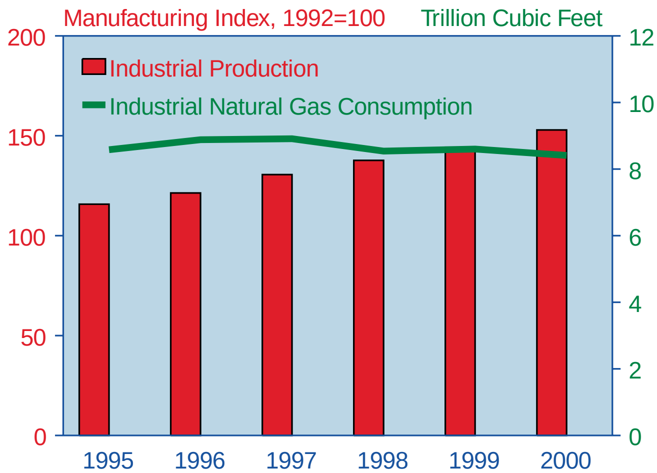
[11] Energy Information Administration, *Natural Gas Annual 2000,* DOE/EIA-0131(2000) (Washington DC, November 2001), and earlier issues, Table 1.

manufacturing accounted for 83.2 percent of the natural gas consumed in the industrial sector, either as a fuel or feedstock, in 1998.[12] More nautral gas is used in the industrial sector than in any other end-use sector, despite declines in industrial gas consumption since 1997 (Figure 5), in part because of a shift toward less energy-intensive industries and more efficient equipment.

Weather-Related Factors

Cold weather was a key reason for the increases in natural gas demand during 2000, particularly in the residential and commercial sectors, which use natural gas primarily for space heating. Natural gas transmission and delivery systems are designed to meet peak demand requirements. Peaks usually occur during the winter, when daily consumption in the combined residential and commercial sectors can be nearly double the annual average consumption on a per-day basis. As a result of increased demand in the electricity generation sector, the total amount of natural gas consumed in the winter has increased, and the amount of spare production and transportation capacity during peak demand periods has decreased.

Figure 5. Index of U.S. Industrial Production and Industrial Consumption of Natural Gas, 1995-2000



Source: Federal Reserve Board, "Federal Reserve Statistical Release," G17(419), Supplement (various issues); and Energy Information Administration, *Natural Gas Annual,* DOE/EIA-0131, Table 14 (various issues).

The warm winters of 1997-1998 and 1998-1999, when temperatures were 8.5 percent and 9.2 percent higher than the 1960 to 1990 averages,[13] obscured the expansion in the underlying capability to consume natural gas. During that time, the capacity of gas-consuming equipment continued to build as new gas-heated homes were added to the housing stock and gas-fired facilities were added to electricity generation capacity. When temperatures plunged in some regional markets in mid-January 2000[14] and then again the following winter, demand shot to new heights, not only in the residential and commercial sectors (where a 10-percent rise in the number of heating degree days would increase aggregate natural gas consumption by an estimated 8.2 percent and 7.3 percent,[15] respectively) but also in the electricity sector. Although the increase in demand in the electricity sector is small in comparison with the weather effects on residential and commercial consumption, an increase in gas-fired generation can significantly worsen an already tight supply situation.

During the winter of 2000-2001, frigid temperatures arrived early in the season with below normal levels in November and December. In December 2000, cold weather gripped the Northeast and Midwest so that, even on a national basis, heating degree days showed a 20-percent increase over 30-year norms[16] and a 32-percent increase over December 1999. Natural gas consumption in the residential and commercial sectors during the month was 26.3 percent higher than the average for the preceding 5 years. Although temperatures moderated by mid-January 2001 and were near or slightly above normal in February and March 2001, the 2000-2001 heating season overall was the first colder-than-normal winter since 1995-1996.

Weather effects were also evident in the California natural gas market. The availability of hydropower had been sharply reduced by 2 years of drought in the Northwest, leaving California and other parts of the West to rely more on natural-gas-fired generation. In addition, very warm summer weather in 2000 followed by cool temperatures in the fall increased the demand for natural gas for air conditioning in the summer and for space heating

[12]On a delivered basis. Does not include losses for electricity generation.

[13]U.S. National Oceanic and Atmospheric Administration, *Heating Degree Days,* Historical Climatology Series 5-1, Table 3-3 (various issues).

[14]Nationally, natural gas consumption in the residential and commercial sectors in January and February 2000 was only 1.3 percent higher than the average for the same months in the previous 5 years. However, the aggregate data obscure the sharp demand increases that occurred during several weeks and in some regional markets. The cold weather mainly affected New England and then extended to the Middle Atlantic States, with temperatures in the Northeast shifting from 17 percent warmer than normal to as much as 24 percent colder than normal. In total, weekly heating requirements in the Northeast increased by an estimated 40 percent. See Energy Information Administration, *Impact of Interruptible Natural Gas Service on Northeast Heating Oil Demand*, SR / OOG / 2001-01 (Washington DC, December 2000), p. 29.

[15]Energy Information Administration, *Short-Term Energy Outlook* (Washington DC, November 2001), Table 6.

[16]Energy Information Administration, *Natural Gas Monthly*, DOE / EIA-0130(2001 / 03) (Washington, DC, March 2001), Table 26.

in the fall. Nationally, hydropower, which provided 7 percent of the electricity generated in 2000, declined by 15 percent from 1998 to 2000. An increase in gas-fired generation—nearly doubling, from 308 billion kilowatthours in 1998 to 612 billion kilowatthours in 2000—has more than compensated for the decline in hydropower.

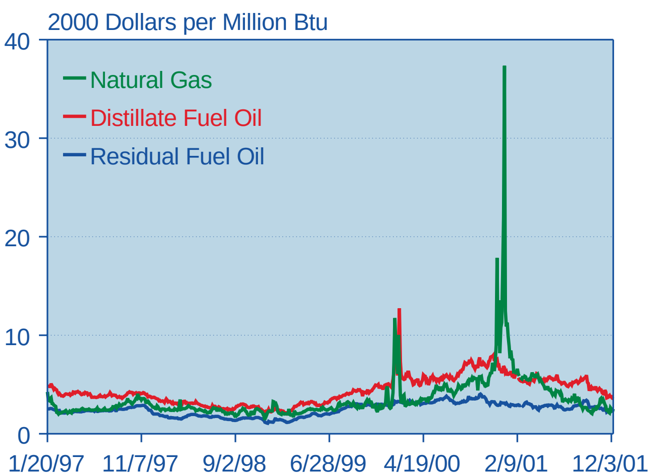
Competing Fuels

Dual-fuel capable equipment, found mostly in large commercial, industrial, and electricity generation applications, can be adjusted to switch between one fuel and another, sometimes in a matter of hours. The choice of which energy form to consume frequently is based on relative prices, relative combustion efficiency, availability or security of supply, emissions, and other considerations. The most common dual-fuel combinations are natural gas and distillate fuel and natural gas and residual fuel.

Natural gas citygate prices and petroleum spot prices provide an indication of the prices paid by power generators for immediate fuel supplies. The prices in the New York City area show that, since 1997, natural gas has generally been less expensive than distillate fuel but more costly than residual fuel oil (Figure 6). Despite some fluctuations in early 2000, natural gas prices had been lower than distillate prices and not much higher than residual prices, until a combination of cold weather and low stocks pushed natural gas prices higher in December 2000. Generators responded by reducing natural gas purchases and increasing petroleum consumption in those periods.

Without the flexibility provided by dual-fuel equipment, demand pressures on natural gas prices in December 2000 would have been even greater. That flexibility also is significant because it promotes interrelatedness between different fuel markets, with conditions in one market affecting conditions in another. The likely switching from relatively high priced natural gas in late 2000 to lower cost alternatives, such as petroleum fuels, probably increased demand, and hence prices, in other fuel markets.

Figure 6. Fuel Spot Prices in the New York City Area, January 1997-October 2001



Source: Reuters News Service.

Natural Gas Supply

Gas supplies consist of domestic production and imports of gas from foreign suppliers. In addition, gas is available from storage during the heating season. Storage gas during the non-heating season months (April-October) represents a demand item, however, because gas is injected during the off-peak months to be available for withdrawal during the heating season. Increased demand for natural gas in 2000 meant that, if supply volumes did not rise correspondingly, prices would increase. The price path since early 2000 indicates that supplies initially did not keep pace with the rapidly expanding consumption requirements.

The supply response to increased prices differs in the short run and longer run. As demand increases cause prices to rise, the prompt response is an attempt to provide a larger volume from the existing supply capacity, because changes in production capacity cannot occur immediately. Production capacity increases require some time for activities such as securing investment capital, preparing sites, installing new equipment, hiring and training personnel, and developing additional infrastructure.

If a significant amount of spare supply capacity exists, volumes can be increased in the short term by increasing utilization. Companies with spare capacity generally respond promptly to opportunities for additional sales or services. Under such conditions markets adjust primarily through volume changes. As utilization rises toward capacity limits, however, further supply increases become more difficult and costly. When utilization rates approach maximum levels, the supply becomes increasingly inelastic, and market adjustments result primarily in price increases. Higher prices reflect either the higher costs of operation or the scarcity of the commodity, and they motivate consumers either to reduce consumption or to redirect some portion of demand to substitute fuels.

Industry Response to Increased Prices

Natural gas prices in January 2000 averaged $2.40 per million Btu at the Henry Hub. Daily prices began a gradual increase that reached $3 in mid-April and $4 at the end of May, eventually to exceed $10 before the end of December. The price increases led to a number of industry actions aimed at boosting production to take advantage of the opportunity for greater revenues and profits.

Attempts by producers to increase output from existing capacity were impeded by the high utilization rates prevailing at the time. Estimated U.S. natural gas effective productive capacity[17] had declined during 1999 because of a preceding falloff in gas drilling.[18] Estimated capacity utilization reached 95 percent in 1999. As prices rose, drilling for gas prospects increased. Despite industry concerns about the availability of drilling rigs and personnel, the number of rotary rigs drilling for gas rose substantially in 2000 to reach 879 at the end of the year, well above the previous high set in 1997[19] and more than double the most recent low of 362 gas rigs reported in April 1999.

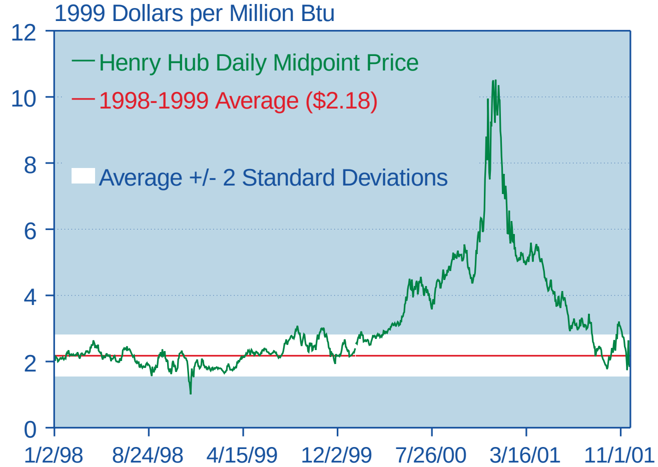
Production from incremental drilling initially served as an offset to the effects from the prior drilling slump.[20] Market demand expanded so substantially, however, that for a time it was able to absorb all additional production and prices still rose. Eventually, demand expansion slowed, and productive capacity expanded sufficiently to lead to a slight decline in productive capacity utilization rates in 2000.[21]

The increase in domestic supply since early 2000 has been achieved despite a number of factors that have impeded efforts to expand production. As prices for both oil and natural gas climbed from the depressed levels of 1998-1999, many operators hedged their prices for future production at the prices available in the spring of 2000, which seemed unusually high at the time, little knowing that the price would continue to climb in successive months. Although the continuing price gains served as an incentive for additional investment, some operators had locked in prices for later production that were not as high as the prices that prevailed when the volumes were delivered. Consequently, at least some portion of the higher prices did not transfer to the companies in the form of higher revenues, limiting cash flow and reducing investment budgets from what they otherwise would have been. Another factor limiting cash flow was the need to repay debts incurred during the period of low prices in 1998 and 1999. Additional difficulties included a scarcity of drilling rigs and drilling crews, with 6- to 8-month backlogs on specific pieces of equipment, rising prices in all areas of upstream support, and the distraction of mergers or downsizing activity in significant portions of the industry.

Another factor impeding more rapid expansion of domestic production was the nature of the price increase itself. Although the high and rising prices during 2000 undoubtedly motivated high utilization of all available capacity and provided additional cash flow from which to fund investments, new project evaluations at that time were not based on the peak prices.[22] Spot prices at the Henry Hub in 1998-1999 averaged $2.18 per million Btu, within a normal range of $1.54 to $2.81. When prices rose rapidly beyond $3, many investors were not sure that the prices would remain at the higher level. They required a clear pattern of sustained higher prices to have the higher prices factored into investment decisions. The judiciousness of that approach to investment evaluation is apparent in view of the subsequent falloff in prices to levels below $3 (Figure 7).

Expanded operations and new investments led to increased production. Domestic production reached 19.0 trillion cubic feet in 2000, an increase of almost 0.2 trillion cubic feet from 1999; however, the increase would not have been sufficient by itself to meet the increase in consumption of more than 0.9 trillion cubic feet. Additional supplies were needed from storage and from sources outside the United States.

Figure 7. Natural Gas Spot Market Prices at the Henry Hub, 1998-2001



Source: *Natural Gas Intelligence: Daily Gas Price Index.*

[17] *Natural gas effective productive capacity* is a measure of the maximum production available from natural gas wells.

[18] Energy Information Administration, "Natural Gas Productive Capacity for the Lower-48 States," web site www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/nat_gas_productive_capacity_2001/sld001.htm (May 2001).

[19] Rotary rigs running have been identified as drilling for oil or gas only since 1988, and the comparison is limited to the period since then.

[20] For more detail on the lagged supply response, see Chapter 2 of this report.

[21] Energy Information Administration, "Natural Gas Productive Capacity for the Lower-48 States," web site www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/nat_gas_productive_capacity_2001/sld001.htm (May 2001).

[22] B. Campbell, "Hard at Work: Independents Plan to Go the Extra Mile," *The American Oil & Gas Reporter* (January 2001), pp. 43-46.

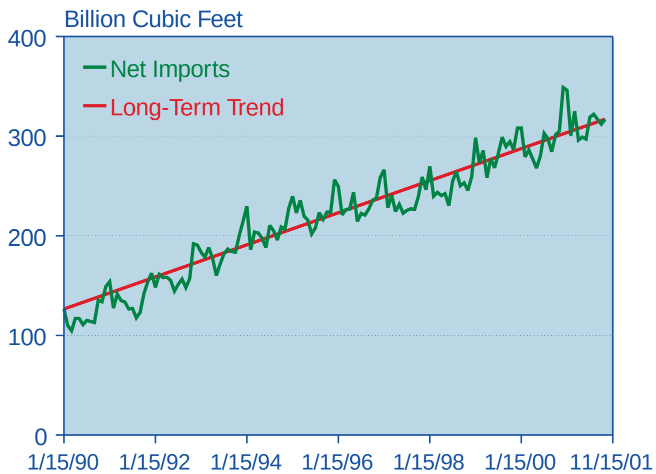
Natural Gas from Foreign Sources

U.S. international gas trade consists of trade via pipeline with Canada and Mexico and trade in liquefied natural gas (LNG)[23] via trucks and tanker ships. Net imports of natural gas to the United States, which have grown steadily since 1986, accounted for 16 percent of U.S. consumption in 2000. Like domestic gas operations, natural gas imports operate on a fixed infrastructure at any particular time. Although the import infrastructure operates generally at high utilization rates, the extraordinary prices for natural gas in the latter part of 2000 led to levels that exceeded the long-term trend (Figure 8).

U.S. Trade with Canada. The United States is a net importer of natural gas from Canada. Gas imports from Canada have grown almost every year since 1986, reaching 3,544 billion cubic feet in 2000—more than 5 percent higher than in 1999 and more than four times the volume recorded in 1986. Imports from Canada represented approximately 94 percent of total U.S. natural gas imports in 2000. The weighted average border price of gas imports from Canada in 2000 was $3.90 per million Btu, about 9 percent higher than U.S. wellhead prices.

Most of the growth in imports from Canada during 2000 can be attributed to increased utilization of the Portland Pipeline and two new cross-border pipeline facilities that became operational: the Maritimes & Northeast Pipeline (Maritimes) and the Alliance Pipeline. Maritimes became operational in January 2000, providing approximately 400 million cubic feet of capacity per day. Maritimes links the Sable Island Offshore Energy Project, off Nova Scotia in the North Atlantic, to Wells, Maine, and supplies gas to the New England markets. In 2000, Maritimes shipped about 88 billion cubic feet of natural gas. The Alliance Pipeline, with a capacity of 1.3 billion cubic feet per day, crosses Alberta through Saskatchewan into North Dakota and provides service to the Chicago area markets. Alliance began operations in December 2000, when the pipeline transported 825 million cubic feet per day, or more than 63 percent of its capacity.[24]

Figure 8. Total U.S. Natural Gas Imports by Month, 1990-2001



Source: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130 (various issues).

U.S. Trade with Mexico. The United States is a net exporter of natural gas to Mexico. Natural gas pipeline exports to Mexico totaled 105 billion cubic feet in 2000,[25] representing a record level of sales to Mexico and an increase of 72 percent from 1999 volumes. The United States also imported approximately 12 billion cubic feet of natural gas from Mexico in 2000, a decrease of 79 percent from the 55 billion cubic feet imported in 1999. The decline in imports and increase in exports likely were the result of increased domestic demand for natural gas and relatively flat levels of natural gas production in Mexico. Thus, Mexico was not in a good position to increase sales to the United States.

Liquefied Natural Gas Trade. After nearly doubling in 1999, LNG imports continued their robust growth during 2000, reaching 226 billion cubic feet, a 38-percent increase over the previous year. In 2000, the continental United States had two operational LNG receiving terminals: at Everett, Massachusetts, and Lake Charles, Louisiana. LNG imports serve as important supplemental gas supplies in the markets near those terminals. In 2000, imports into Everett totaled 99 billion cubic feet, an increase of 3 percent over 1999. The Lake Charles facility received 127 billion cubic feet, an increase of almost 89 percent over 1999. The key factors behind the large increases in LNG import volumes were available capacity at the importing terminals and the ability to gain use of additional tankers for transport, facilitated by attractive prices. Although less than the $3.90 paid for Canadian imports and only slightly higher than the average U.S. wellhead price of $3.58 per million Btu, the average price of $3.20 per million Btu for LNG imports in 2000 was 46 percent above the average price of $2.19 in 1999.

[23]Liquefied natural gas (LNG) is natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

[24]Additional information on current capacity and planned expansions is available in Energy Information Administration, "Natural Gas Transportation—Infrastructure Issues and Operational Trends," web site www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/natural_gas_infrastructure_issue/pdf/nginfrais.pdf (October 2001).

[25]The United States also exported approximately 271 million cubic feet of LNG by truck, crossing the border at Nogales, Arizona, and San Diego, California. LNG deliveries to Mexico began in 1998, when 33 million cubic feet was shipped to Mexico through Nogales.

Natural Gas Storage

Storage facilities are essential to the U.S. natural gas industry. Underground natural gas storage inventories provide suppliers with the means to meet customer requirements during the heating season,[26] especially on peak demand days.[27] Based on the "snapshot" of storage as of the end of March 2000, the industry seemed to be in good shape: with the entire refill season ahead, inventories slightly exceeded the previous 5-year average. However, net storage injections for the first months of the refill season were well below average, primarily because of the high prevailing gas prices.

Beginning in early 2000, spot prices began to rise steadily. In mid-April, just after the beginning of the refill season, they exceeded $3 per million Btu—levels seen only briefly in the fall of 1999. By the middle of May, prices were climbing steeply and jumped to more than $4 per million Btu by the end of the month. Undoubtedly, a number of operators delayed injecting gas into storage in the hope that prices would fall. Although prices dipped briefly during July, they took off again in August and by the middle of September had crossed the $5 per million Btu threshold.

By the end of August 2000, storage levels were 2,190 billion cubic feet, which was not only well below the 5-year average but 55 billion cubic feet below the record low for the 1990s. In the last 6 weeks of the refill season, injections surged above average rates as the industry rushed to put gas in storage for the coming heating season. As of the end of October 2000, stocks stood at 2,732 billion cubic feet—the lowest level for storage at the beginning of the heating season since 1976.

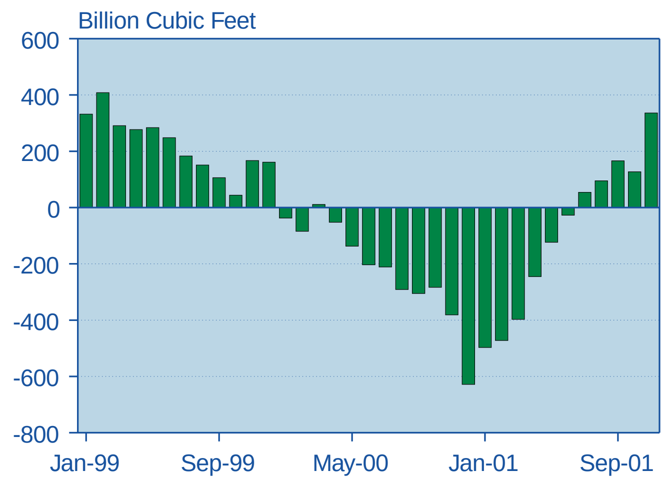
The 2000-2001 heating season began with relatively cold temperatures in November and December 2000. The frigid temperatures caused a surge in demand that led to soaring prices and a rapid drawdown of storage levels. By the end of December, the spot price at the Henry Hub hit $10.52 per million Btu and stock levels stood at 1,719 billion cubic feet—nearly 27 percent below the 5-year average for that point in the heating season. With inventory levels well below expected norms, concerns emerged that they might not be sufficient to last through the heating season. Fortunately, temperatures moderated for the last 3 months of the heating season and the pace of withdrawals eased; so the deficiency between the average and current inventories did not worsen (Figure 9).

Working gas inventories at the end of the heating season were 742 billion cubic feet, 16 billion cubic feet below the previous record end-of-season low, and the Henry Hub spot price averaged slightly more than $5 per million Btu. At that time, a major concern was that the replenishment of the severely depleted storage volumes would add demand pressure to the market, with refill volumes competing against expected demand for electricity generation as cooling requirements increased during the summer. Given the still elevated prices in the spring of 2001, the prevailing view was that prices would remain high as the industry was challenged to meet the overall demand surge expected in mid-2001.

Market Adjustments in 2001

Natural gas prices have declined substantially since early 2001, and supplies have been sufficient to allow record volumes to be added to storage. EIA projects that natural gas prices will be higher in 2001 than in 2000; however, the expected high average for the year is based largely on the extraordinary prices in the early months. Prices have declined throughout 2001, and the trend is expected to continue through 2002.[28] Monthly wellhead gas prices are expected to average $3.98 per million Btu in 2001, with decidedly lower prices expected in the latter part of the year than in the early months. In 2002,

Figure 9. Working Natural Gas in Storage: Deviations From 5-Year Average, 1999-2001



Source: Energy Information Administration, *Short-Term Energy Outlook*, Table A4, web site www.eia.doe.gov/emeu/steo/pub/contents.html (November 2001).

[26]The *heating season* for natural gas markets is considered the 5-month period from November through the following March. The other 7 months, April through October, are an inventory-building period called either the "non-heating season" or "refill season."

[27]In addition to meeting winter demand loads, storage also is used for load balancing on pipeline systems, "parking" of gas between days, and capturing arbitrage opportunities.

[28]Projected values for 2001 and 2002 in this section are from Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov / emeu / steo / pub / contents.html (December 2001).

prices are projected to average $1.91 per million Btu, which would be a 52-percent drop. This price projection reflects changes in a number of key market conditions or trends.

Natural gas demand has been affected by a slowdown in the U.S. economy and by milder temperatures. As a result, consumption in 2001 is expected to be roughly 1 trillion cubic feet lower than in 2000. Demand in the residential and commercial sectors is projected to increase slightly, by an estimated 50 billion cubic feet. The largest impact is expected in the industrial and electricity generation sectors, where combined consumption is expected to decline by 960 billion cubic feet as a result of the economic slowdown and, in part, switching to other fuels. Natural gas consumption for lease and plant fuel and for pipeline operations is expected to increase by 30 billion cubic feet in 2001.

The domestic natural gas industry continued to expand in 2001. The number of rigs drilling for gas prospects has continued to rise, to a record 1,068 in mid-July. Gas well completions have risen accordingly, increasing by 45 percent in 2000 over the 10,513 gas wells completed in 1999 and expected to surpass 20,000 wells in 2001.[29] The large number of gas well completions has increased effective productive capacity and resulted in the replacement of produced gas with proved reserve additions. Proved reserves of dry natural gas have increased in 6 of the past 7 years, but the net gain of 6 percent between 1999 and 2000 is by far the largest increase since EIA began estimating the Nation's proved gas reserves in the late 1970s.[30] U.S. natural gas production is expected to reach 19.5 trillion cubic feet in 2001, which would be the highest level since 1974.

Gas imports from Canada are also expected to increase. Pipeline capacity newly opened in 2000 will provide larger volumes in 2001 and beyond because it will be operated over a full 12 months and utilization rates will grow from initial operation levels. With its capacity of 1.3 billion cubic feet per day, the Alliance Pipeline may play a pivotal role in satisfying some portion of the increased demand for the foreseeable future. Furthermore, in October 2000, Maritimes filed an application with the Federal Energy Regulatory Commission (FERC) requesting approval to expand its transportation capacity to eastern Massachusetts by constructing two additional pipelines, Maritimes III and Algonquin's HubLine. This would enable the transport of an additional 360 million cubic feet per day when it becomes operational in 2002.

Natural gas demand in Mexico is expected to continue growing because of anticipated additions of natural-gas-fired electricity generation facilities. Investments in pipelines to export gas to Mexico from Texas, California, and Arizona have grown rapidly in recent years; and the trend is likely to continue. The majority of new cross-border pipeline projects have been designed to supply natural gas to electricity generators in Mexico. Although Mexico has substantial gas resources, rates of field development are not expected to be sufficient to meet growing demand, and Mexico is likely to remain a net importer of U.S. natural gas for years to come.[31]

LNG imports have considerable potential as a source of natural gas supply for the United States. Expansion of LNG imports is expected in the near future as two U.S. LNG-receiving facilities are reopened for imports. The Elba Island terminal near Savannah, Georgia, has received clearance from the FERC to resume LNG import activities, and initial shipments began in October 2001. Although the Cove Point LNG facility in Maryland has not received any shipments since 1980, in October 2001 the FERC approved an application for resumption of its operation. Imports are expected to begin arriving at the facility in 2002.[32]

In an action with important implications for East Coast markets, the U.S. Coast Guard, as a result of the heightened state of national security following the September 2001 terrorist attacks in Washington, DC, and New York City, suspended LNG shipments into Boston harbor. The ban was lifted on October 12, but the Mayor of the City of Boston requested an injunction because of fears of possible attacks on the vessels. A U.S. District Court Judge refused to issue the injunction, and the first LNG tanker arrived at the nearby terminal in Everett, Massachusetts, on October 29. The Everett facility received 45 LNG shipments totaling 99 billion cubic feet in 2000. The additional gas supplies from LNG imports should help to alleviate concerns about winter supply in the New England States.

In addition to small volumes of LNG exports trucked to Mexico, the United States also exported 66 billion cubic feet of LNG to Japan by oceangoing tanker in 2000. The LNG that is exported to Japan is produced in the Cook Inlet area of Alaska and is surplus to local market needs

[29] Energy Information Administration, *Monthly Energy Review*, November 2001, DOE/EIA-0035(2001/11) (Washington, DC, November 2001). Estimate for 2001 based on 17,090 gas wells completed in the first 10 months of 2001.

[30] Energy Information Administration, *Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 2000 Annual Report*, DOE/EIA-0216(2000) (publication pending).

[31] For example, see Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001).

[32] The Williams Companies, Inc., "FERC Grants Certificate To Reactivate Williams' Cove Point LNG Terminal," News Release (October 12, 2001), web site www.williams.com/news/newsreleases/rel809.html.

in southern Alaska. It is sold to Japan in part because there are no LNG receiving terminals on the West Coast or pipelines to transport the gas to lower 48 markets. Renewed industry interest in LNG as a source of natural gas has led to proposals to construct West Coast facilities to take advantage of LNG from Alaska and other sources.[33]

Net additions to working gas in storage during the 2001 refill season have occurred at a record pace. Working gas stocks are estimated to have reached more than 3,100 billion cubic feet by November 1, 2001, providing an additional margin above the unofficial target of 3,000 billion cubic feet for the start of the heating season and exceeding stock levels at the same time in 2000 by almost 400 billion cubic feet. For most of November 2001, attractive spot and futures prices and unseasonably warm temperatures across much of the country have contributed to a continued stock build. The buildup of 47 billion cubic feet during the first 23 days of November 2001 contrasts with the net withdrawal of almost 200 billion cubic feet during the same period in 2000. As of November 23, 2001, working gas stock levels stood at an estimated 3,156 billion cubic feet, which is 25 percent, or more than 600 billion cubic feet, higher than the 2000 level.

The large volumes of working gas in storage are expected to mitigate upward price pressures during the 2001-2002 heating season. Thus, natural gas markets appear to have met what was identified in the earlier EIA report as the most serious short-term challenge: "to increase production rapidly enough to satisfy natural gas demand at reasonable prices."[34] The recent return of prices to the range observed in 1998-1999, however, was achieved with adjustments on both sides of the market.

Almost 2,400 billion cubic feet of natural gas is estimated to have been added to storage during 2001, which represents average incremental demand of 11.1 billion cubic feet per day. This is almost 4 billion cubic feet per day more than the average of 7.4 billion cubic feet per day during the 2000 refill period. Despite the additional demand pressure, prices have trended downward during this period—a clear indication that the relative supply position has improved greatly over last year. However, the expected increases in gas-consuming capacity indicate a continuing need for supply expansion to be adequate for the growing market.

The potential for natural gas consumption is expected to increase in the mid-term with the pace of new natural-gas-heated housing starts continuing at present levels. By 2005, residential natural gas consumption is expected to be 5.4 trillion cubic feet, compared with 5.0 trillion cubic feet in 2000.[35] Gas-fired additions to electricity generation capacity are expected to be 1.4 gigawatts in 2001, and total natural-gas-fired capacity is expected to grow by 2.4 percent per year from 2002 through 2005.[36] As a result, natural gas consumption to produce electricity (excluding cogeneration) in 2005 is expected to be 5.4 trillion cubic feet, compared with 4.2 trillion cubic feet in 2000.[37] Consumption by cogeneration facilities is also expected to increase, given the expected increase in cogeneration capacity.

As the potential for increased consumption grows in the residential and electricity generation sectors, so does the potential for weather-driven events like those documented in early and late 2000. Severe weather can result in rapid increases in demand and gas prices. Fuel switching to petroleum, reducing or halting operations, and discontinuation of service to interruptible customers will continue to be helpful in providing high-priority customers the additional natural gas supplies required during periods of peak demand.

Natural Gas Transmission Infrastructure

The natural gas infrastructure, especially transmission capacity, faced greater load requirements during 2000 as gas demand increased. Despite the increased demand for pipeline capacity, the movement of natural gas from production areas to end-use markets encountered very few infrastructure difficulties. Although the use of available natural gas pipeline capacity rose to high levels (90 to 100 percent in many locations), there were few, if any, reported sustained instances of service disruptions or capacity constraint.[38] The demand for natural gas appears to have approached pipeline capacity limits in some fast-growing market areas, including California, Florida, and New York; however, the conditions that underlie those situations are often short term in nature and readily resolved. For example, a localized capacity constraint that occurred periodically in the metropolitan

[33]For further discussion of proposed LNG import facilities, see Chapter 3 of this report.

[34]Energy Information Administration, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*, SR / OIAF / 2001-02 (Washington, DC, May 2001), p. 20.

[35]Energy Information Administration, *Annual Energy Outlook 2002,* DOE / EIA-0383(2002) (Washington, DC, December 2001), Table 13.

[36]Energy Information Administration, *Annual Energy Outlook 2002,* DOE / EIA-0383(2002) (Washington, DC, December 2001), Table 9. Electricity generation capacity is summer capacity.

[37]Energy Information Administration, 110 *Annual Energy Outlook 2002,* DOE / EIA-0383(2002) (Washington, DC, December 2001), Table 13.

[38]A more detailed discussion of transmission systems is available Energy Information Administration, "Natural Gas Transportation—Infrastructure Issues and Operational Trends," web site www.eia.doe.gov / pub / oil_gas / natural_gas / analysis_publications / natural_gas_infrastructure_issue / pdf / nginfrais.pdf (October 2001).

area of Boston, Massachusetts, was alleviated when an expansion of the regional Tennessee Gas Pipeline system was completed in 2001.

The natural gas pipeline industry continues to respond to actual and projected increases in demand. Through September 2001, approximately 21 interstate natural gas pipeline projects were completed in the United States, out of a total of 59 scheduled for completion during 2001. The completed projects added 3.8 billion cubic feet per day of new capacity and 1,660 miles of pipeline to the existing 280,000-mile U.S. pipeline grid. If all the remaining scheduled 2001 projects are completed, an additional 6.5 billion cubic feet per day of capacity will be added to the network.

Market Area Influences on the Transmission System

During the past decade, natural gas pipeline capacity growth into major natural gas market areas was substantial, driven by growing demand in all segments of the consumer market. The Midwest Region showed the largest volumetric increase, 5.5 billion cubic feet per day (24 percent), and capacity into the Western Region grew by the largest percentage, 52 percent (3.0 billion cubic feet per day). The Northeast Region had both the largest percentage increase (532 percent) and volumetric increase (2.5 billion cubic feet per day) among the regions with access to Canadian supplies.

The Northeast Region's interstate natural gas pipeline capacity is already being utilized at high load levels during peak months. Increasing demand for natural gas to feed industrial growth and new and planned natural-gas-fired electric power generators has burdened the local infrastructure, which has occasionally had transitory capacity constraint problems. At least four major pipeline expansion projects are scheduled to be completed to serve the New England market before the end of 2001, and two new local pipelines are proposed for implementation in 2002. Those six projects include the possible installation of 1.3 billion cubic feet per day of new capacity in the Boston area alone.

Elsewhere within the Northeast Region, the New York City area is the destination and focal point of a number of major pipeline expansions and new lines. Currently, approximately 3.2 billion cubic feet per day of natural gas pipeline capacity reaches the area. For example, the Cross Bay Pipeline, a joint project between Duke Energy Corporation and The Williams Companies (Transcontinental Gas Pipeline Company), would increase natural gas pipeline capacity into New York City and Long Island by 125 million cubic feet per day by late 2002, where currently only about 650 million cubic feet per day is available.

New natural gas pipeline capacity into the Northeast in 2002 could reach 0.5 billion cubic feet per day, and expansions within the region could total 1.1 billion cubic feet per day. All told, a total of more than 6.5 billion cubic feet per day of new capacity (more than 30 projects) could be installed into and within the Northeast Region, although it remains to be seen whether all the projects currently planned will garner the necessary shipper commitments to survive market and FERC scrutiny.

Pipeline capacity into the Midwest Region has grown rapidly. During the past 2 years alone (1999 and 2000), regional import capacity grew by 5 percent, primarily because of the completion of the Alliance Pipeline in 2000. Utilization of the new capacity installed in late 2000 began high and has remained so. During the past heating season (2000-2001), pipeline capacity usage averaged 90 percent and above on those pipelines importing Canadian supplies (Alliance, Northern Border, Great Lakes, and Viking pipeline systems). Yet demand for natural gas in the Midwest Region, including the southern Wisconsin area, is still growing. Several pipeline projects that have been approved or are awaiting regulatory review would provide substantial additional capacity within the region itself.

Although the California market has been the prime target of most of the recent proposals to expand natural gas pipeline capacity in the Western States, other parts of the region also have demanded increases in natural gas pipeline capacity sufficient to handle potential future growth. In Oregon and Washington, a series of proposals have been put forward to build a number of large laterals or new pipelines from the existing mainlines of Northwest Pipeline Company and PG&E Gas Transmission-NW, to serve growing natural gas markets within the northwest portion of the region. Completion of the projects would add approximately 500 million cubic feet per day of new capacity to the area by the end of 2002. An additional 700 million cubic feet per day also could be installed in 2003 if current demand growth factors, especially natural-gas-fired power plant capacity, continue to rise.

The need to supply new natural-gas-fired power plants in Arizona and Nevada is also generating proposals to expand available natural gas pipeline capacity to those areas as well. Several proposed interstate pipeline expansion projects slated to serve the California market may initially provide all or part of their capacity to markets in Arizona and Nevada. For example, the Questar Southern Trails pipeline, which will terminate at the southern California border, will provide most of its 90 million cubic feet per day of capacity at least initially to new gas-fired power plants in western Arizona. And although the Kern River Transmission Pipeline system was expanded by 135 million cubic feet per day in July 2001 to increase available capacity to California, 220 million cubic feet per day of the system's capacity will be drawn off in 2002 to serve a new gas-fired power plant northeast of Las Vegas, Nevada. Kern River is expected to complete its system-wide expansion and double its current capacity to 1.6 billion cubic feet per day in 2003. Until then, the pipeline may have difficulty meeting the needs of both markets.

Over the next several years, as much as 2.7 billion cubic feet per day of new pipeline capacity could be installed in the Western Region if all the 17 projects currently planned are actually completed. That would represent a major reversal from 1999-2000, when pipeline capacity within and into the Western Region grew by only 49 million cubic feet per day. It remains to be seen, however, whether the market conditions shift during the interim and demand for new capacity drops. If that does happen, then it is possible that only a fraction of the currently proposed capacity actually will be installed.

Supply Influences on Transmission Capacity Expansion

The growth in natural gas consumption and production in the past several years has been accompanied by a steady increase in new pipeline capacity exiting supply areas. Expanded coalbed methane production in the Rocky Mountains area and natural gas development in the deep waters of the Gulf of Mexico have led to the installation of several new lines and proposals to construct additional pipelines exiting the areas. Between 1997 and 2000, for example, 22 natural gas pipeline projects were completed in the Gulf, adding 8.2 billion cubic feet per day of new pipeline capacity. Plans are underway for a number of new pipelines in the Gulf, including the 55-mile, 500 million cubic feet per day Canyon Express system, which will be constructed in deep water 120 miles southeast of New Orleans. Another major project announced for the Gulf is the 74-mile, 1 billion cubic feet per day Okeanos Project designed to transport gas from new platforms in the developing NaKika deepwater field.

In the Rocky Mountains, proved natural gas reserves in the Wyoming / Montana area increased by 37 percent, or 3.6 trillion cubic feet, between 1990 and 1999. To accommodate the supply growth, a number of new gathering and header systems have been built in the area. Four projects totaling 1.3 billion cubic feet per day were completed in 1999-2000 to move natural gas from the production field to transmission lines, and several proposals have been made for a significant expansion of the area's interstate takeaway capacity (as much as 2.1 billion cubic feet per day could be added between 2001 and 2003). Proposals include several new long-haul pipelines to transport natural gas from the Cheyenne Hub in northern Colorado to interconnections with major interstate pipelines in Kansas, which would provide shippers with a substantial increase in access to Midwest markets.

Since 1998, natural gas import capacity from Canada has increased by 58 percent into the Midwest Region and by 23 percent into the Northeast Region. The installation of the Maritimes and Northeast Pipeline and the Portland Natural Gas Pipeline into the Northeast Region in 1999 (578 million cubic feet per day) provided 15 percent of the increase in natural gas import capacity from Canada that year. The completion of the Alliance Pipeline System (1.3 billion cubic feet per day) into the Midwest in 2000 represented another 10-percent increase in overall Canadian gas import capacity.

Transmission Outlook

In light of the available capacity and capacity utilization patterns, it seems unlikely that the natural gas infrastructure played a significant sustained role in the price spikes of 2000 and early 2001. The available volumes of natural gas simply were inadequate to satisfy total demand. The delivery system moved as much gas as was available to customers, albeit at prices higher than were typical through the 1990s.

Price spikes may occur this winter in localized or regional markets when demand or supply conditions shift. Such events, when limited in geographic scope, tend to be transitory. The experience in California from late 2000 to mid-2001 is a notable exception, as discussed below.[39]

Electricity and Natural Gas Prices in California

Normally, price increases bring a market into equilibrium by both increasing supply and decreasing demand. In some cases, however, especially in the short term, either supply or demand may not readily adjust, and price increases can be extreme. Unusually high prices in California's electricity and natural gas markets in 2000 and 2001 were caused by rigidities of supply and demand in both markets. Whether such price spikes will occur again in the future will depend on whether the rigidities in supply and demand can be alleviated.

[39] Additional information on California gas markets in 2000-2001 is available in Energy Information Administration, "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply," web site www.eia.doe.gov / emeu / steo / pub / special / california / june01article / casummary.html (June 2001).

The California Electricity Market

The unusually high wholesale prices for electricity in California reflected a sharp decline in hydroelectric supply due to low precipitation levels in the Northwest; a lack of sufficient electricity generation and transmission capacity to compensate for the reduction in hydroelectric generation; and the rigidity of electricity demand due to fixed retail prices.[40]

On the electricity supply side, hydroelectric generation in the Northwest was 14 percent lower in 2000 than in 1999, amounting to a reduction of 46.4 million megawatthours in total Northwest generation. In the last 7 months of 2000, hydroelectric generation was 19 percent lower than in the same period in 1999, a decline of 28.7 million megawatthours.[41] In California, natural-gas-fired generation made up some of the deficit. Total annual generation from natural-gas-fired power plants in California rose by 31.7 percent in 2000, a gain of 27.2 million megawatthours over the 1999 level; and during the last 7 months of 2000, gas-fired generation was 19.6 million megawatthours (32 percent) higher than during the same period in 1999. As a result, demand for natural gas increased, contributing to a scarcity of natural gas supplies and higher prices.

On the demand side, retail electricity prices were fixed by regulation for the two largest California utilities. The fixed retail prices, which were lower than those prevailing before the State's restructuring plan was implemented, encouraged electricity consumers to use 6 percent more electricity during 2000 than they had in 1999, even in the face of reduced hydroelectric supplies and higher generating costs. California's largest electric utilities operated under a regulatory requirement that they provide electricity to the State's consumers at fixed rates, regardless of wholesale prices. The scarcity of electricity generation and the high demand caused California wholesale electricity prices to escalate to unusually high levels during the latter half of 2000 and early 2001. Blackouts were the only means for moderating peak consumption, because every available in-State and out-of-State source for electricity had been committed. Even the extremely high wholesale prices could not elicit the electricity supplies necessary to satisfy California's electricity demand.

Building new electricity generation plants and transmission facilities in response to California's recent electricity shortage will likely take some years. During the last 6 months of 2000, no new electricity generation plants went into operation in California. Through October 2001, 1,914 megawatts became operational (Table 2). California's electricity generation capacity may still be inadequate, however, as a result of continuing low levels of hydroelectric generation. Hydroelectricity supply in the Northwest was 37 percent lower during the first 7 months of 2001 than it was during the first 7 months of 2000.[42] Another 8,209 megawatts of capacity are under construction in California and are expected to go into operation by July 30, 2003. Plans for another 1,782 megawatts of new generating capacity have been approved by the State, but construction has not begun on any of those projects.

The reconnection of retail and wholesale electricity prices in California has also taken a step forward. On March 27, 2001, the California Public Utility Commission (CPUC) approved retail electricity rate increases of up to 46 percent for the State's two largest electric utilities. As a result of the retail rate increase and a variety of conservation measures, California utility retail sales posted a modest (0.4 percent) increase during the first 7 months of 2001, from 140.4 million megawatthours in 2000 to 140.9 million megawatthours in 2001.[43]

The California Natural Gas Market

In 1999, 83 percent of California's natural gas supply was transported from outside the State.[44] In 2000, natural gas transmission capacity was not adequate to transport all the gas that was needed to meet demand in the California market, and natural gas prices in the State rose well above those in the rest of the U.S. gas market. A comparison of Henry Hub[45] spot prices with delivered prices to California electric utilities shows that the average annual price difference typically varied between 40 and 70 cents per thousand cubic feet from 1997 through 1999. As gas prices at the Henry Hub rose during 2000, so too did the price of gas delivered to California gas utilities. During the first half of 2000, the differential between the Henry Hub price and the delivered California price stayed within the bounds of the historic price differentials. In the latter part of 2000, however, the

[40] The high marginal cost of natural-gas-fired electricity generation also played a role.

[41] These hydroelectric generation data are for the States of California, Idaho, Oregon, and Washington. The reduction in hydroelectric generation affected electricity consumers not only in California but in the entire four-State region.

[42] The four-State hydroelectric generation for January through July 2000 was 110,522 million kilowatthours and for January through July 2001 was 69,539 million kilowatthours. Energy Information Administration, *Electric Power Monthly*, DOE / EIA-0226(2001 / 09) (Washington, DC, October 2001), p. 20, Table 11.

[43] Energy Information Administration, *Electric Power Monthly*, DOE / EIA-0226(2001 / 09) (Washington, DC, October 2001), p. 57, Table 47.

[44] Energy Information Administration, *Natural Gas Annual 1999*, DOE / EIA-0131(99) (Washington, DC, October 2000), p. 100, Table 45. In 1999, California dry gas production was 372 billion cubic feet, and its interstate receipts were 1,795 billion cubic feet.

[45] The Henry Hub in Louisiana is the physical delivery point for NYMEX futures trading contracts. It is the largest-volume market center for natural gas in North America. The Henry Hub price is a widely used benchmark for upstream prices in the United States and is particularly representative of natural gas production prices in the Southwest and the Gulf of Mexico.

difference between the Henry Hub price and the delivered California gas price increased substantially. By December 2000, the *average* monthly price difference was over $10.00 per thousand cubic feet.[46] On some days during that month, the differences were much larger.

Interstate transmission capacity to deliver natural gas at the California border exceeds the takeaway capacity of California's intrastate pipeline system by approximately 300 to 590 million cubic feet per day.[47] Temporary constraints on interstate pipelines also played a role in limiting supplies to California consumers. For example, on August 19, 2000, the El Paso Natural Gas pipeline experienced a rupture outside of Carlsbad, New Mexico, temporarily reducing gas transmission service. After the rupture, the Henry Hub/California price differentials for September and October rose to 86 cents per thousand cubic feet and 94 cents per thousand cubic feet, respectively, from 38 cents per thousand cubic feet in August.

Since the winter of 2000-2001, overall pipeline transmission capacity to California has been increased, but only by about 2 percent. In June 2001, Kern River Transmission brought into service its Mainline 2001 System

Table 2. California Electricity Generation Plants Built, Under Construction, or Approved for Construction

Project Name	Fuel Type	Capacity (Megawatts)	Completion Date
Plants Completed			
Sunrise	Natural Gas	320.0	June 2001
Sutter	Natural Gas	540.0	July 2001
Los Medonas	Natural Gas	555.0	July 2001
Wildflower Larkspur	Natural Gas/Distillate Fuel Oil	90.0	July 2001
Wildflower Indigo Units 1 and 2	Natural Gas	90.0	July 2001
Alliance Drews	Natural Gas	40.0	August 2001
GWF Hanford	Natural Gas	95.0	September 2001
Wildflower Indigo Unit 3	Natural Gas/Distillate Fuel Oil	45.0	September 2001
Alliance Century	Natural Gas	40.0	September 2001
Calpeak Escondido	Natural Gas	49.5	October 2001
Calpeak Border	Natural Gas	49.5	October 2001
Total		**1,914.0**	
Plants Under Construction			
Calpine Gilroy I, Units 1 and 2	Natural Gas	90.0	December 2001
Huntington Beach	Natural Gas	450.0	January 2002
Calpine Gilroy I, Unit 3	Natural Gas	45.0	December 2001
Calpine King City	Natural Gas	50.0	December 2001
Delta	Natural Gas	880.0	April 2002
La Paloma	Natural Gas	1,048.0	June 2002
Moss Landing	Natural Gas	1,060.0	June 2002
Pastoria	Natural Gas	750.0	January 2003
Elk Hills	Natural Gas	500.0	March 2003
Blythe	Natural Gas	520.0	April 2003
Mountainview	Natural Gas	1,056.0	June 2003
Contra Costa	Natural Gas	530.0	June 2003
High Desert	Natural Gas	720.0	July 2003
Otay Mesa	Natural Gas	510.0	July 2003
Total		**8,209.0**	
Plants Approved But Not Under Construction			
Valero Cogeneration Unit 1	Natural Gas	51.0	April 2002
Valero Cogeneration Unit 2	Natural Gas	51.0	December 2002
Metcalf	Natural Gas	600.0	May 2003
Modesto Irrigation District Woodland II	Natural Gas	80.0	May 2003
Three Mountain	Natural Gas	500.0	April 2004
Midway-Sunset	Natural Gas	500.0	July 2004
Total		**1,782.0**	

Source: California Energy Commission, web site www.energy.ca.gov/sitingcases/status_all_projects.html (November 29, 2001).

[46] *Natural Gas Intelligence: Daily Gas Price Index* for Henry Hub prices; and Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130 (various editions), Table 18.

[47] Energy Information Administration, "Electricity Shortage in California: Issues for Petroleum and Natural Gas," web site www.eia.doe.gov/emeu/steo/pub/special/california/june01article/canatgas.html.

Expansion, which added 135 million cubic feet per day of new capacity. On July 11, 2001, El Paso Natural Gas announced the return to full service of the ruptured pipe near Carlsbad, New Mexico.

Within California, Southern California Gas (SoCal) is proceeding with two projects to increase its intrastate capacity by more than 375 million cubic feet per day by January 2002 (Table 3). These two projects will expand the intrastate receipt capabilities at several points where the SoCal system interconnects with the interstate transmission systems. Pacific Gas and Electric (PG&E) had planned to increase its intrastate system capacity by 200 to 600 million cubic feet per day by January 2003,[48] but those plans are now uncertain due to PG&E's bankruptcy. Table 3 shows other gas transmission projects expected to come into operation by the end of 2002.

Natural gas prices remained high in California through May 2001, even as they declined in other regions of the country, at least in part because local gas utilities and others in the State were injecting as much gas into storage as possible. By the end of August, however, California facilities had 186.7 billion cubic feet of working gas in storage (an increase of 33 percent over same time in 2000[49]), and natural gas prices in the State had fallen to levels near the Henry Hub prices. By November 30, 2001, with gas storage facilities full,[50] prices had declined to $2.19 per million Btu at the southern California border and $2.44 per million Btu at PG&E's citygate—not much higher than the Henry Hub price of $1.77 per million Btu on the same date.[51]

Mid-Term Prospects

Whether electricity generation and natural gas supplies in California will be sufficient to prevent high prices in the future is difficult to predict. The winter of 2000-2001 saw the confluence of a number of factors that might not occur again—rapidly growing electricity and gas consumption, inadequate hydroelectric generation, constrained gas and electric transmission capacity, and a nationwide scarcity of natural gas supplies. Electricity and gas suppliers, however, have an economic incentive to build facilities with sufficient capacity to meet expected demand. Whether capacity will always match California's demand in the future cannot be predicted, especially with respect to unforeseeable circumstances, but given the economic incentive to build the facilities, one would expect any shortfalls to be temporary.

Conclusion

Although the mid-term outlook for U.S. natural gas markets and prices seems relatively stable, a key challenge facing the domestic natural gas industry over time, as stated in the earlier EIA report, is "moderating the

Table 3. Natural Gas Pipeline Projects Serving California

Company Name	Project Name	Interstate Capacity (Million Cubic Feet per Day)	Intrastate Capacity (Million Cubic Feet per Day)	Completion Data
Natural Gas Pipeline Projects Completed, June 2000 - June 2001				
Kern River Transmission Co.	Mainline 2001 System Expansion	135	—	June 2001
Natural Gas Pipeline Projects To Be Completed After June 2001 and Before 2003				
Southern California Gas Co.	2001 System Expansion	—	175	Jan. 2002
Southern California Gas Co.	Kern River Interconnect Expansion	—	200	Jan. 2002
Kern River Transmission Co.	Kramer Junction Interconnect	—	500	Feb. 2002
El Paso Natural Gas Co.	Line 2000 Project	230	—	June 2002
Otay Mesa Generating Co.	Otay Mesa Project[a]	110	—	June 2002
Questar Pipeline Co.	Questar Southern Trails Pipeline	87	—	June 2002
Transwestern Pipeline Co.	Transwestern Red Rock Expansion	150	—	June 2002
Pacific Gas & Electric	Redwood Path	—	200	Sept. 2002
PG&E Gas Transmission-NW	2002 System Expansion	207	—	Sept. 2002
Kern River Transmission Co.	Kern High Power Lateral	—	275	Sept. 2002
Southern California Gas Co.	SoCal Adelanto Lateral	—	200	Nov. 2002
Total		919	NA[b]	

[a]Pipeline capacity from Mexico.
[b]Intrastate capacity is not additive, because some projects are laterals within California that do not start at the California border.
Source: Energy Information Administration, Office of Oil and Gas.

[48]California Energy Commission, *Natural Gas Infrastructure Issues*, P200-01-001 (Sacramento, CA, October 2001), p. 15.

[49]Energy Information Administration, *Natural Gas Monthly*, DOE / EIA-0130(2001 / 10) (Washington, DC, October 2001), p. 26, Table 14.

[50]The total rated capacity of the California facilities (base plus working gas) is 388.5 billion cubic feet. At the end of August 2001, the storage level for base and working gas was 433.3 billion cubic feet, exceeding the rated capacity.

[51]*Natural Gas Intelligence: Daily Gas Price Index*.

recurrence and severity of ‘boom and bust’ cycles while meeting increasing demand at reasonable prices.” Episodes of elevated prices have occurred in the past, such as the winter of 1996-1997, but these events were short-lived, except for the most recent one from early 2000 to mid-2001. Although the difficulties in expanding supplies seem to have been transitory given the eventual turnaround in gas prices, the market experience after 1999 has indicated that the shift in domestic market practices has perhaps introduced a vulnerability to severe high price events. The shift from a regulatory framework to a competitive one has encouraged the natural gas industry to manage costs differently and more efficiently. The shift to streamlined operations and “just-in-time” principles has reduced the additional productive capacity and infrastructure that might have been available under earlier regulation to mitigate the impact of the sudden occurrence of a high level of demand.

Maintaining productive capacity for natural gas “depends on the drill bit,” as has always been true for this extractive industry. In recent years, however, the relationship between production and new drilling has intensified as the share of natural gas production from relatively new wells has increased. This trend reflects the competitive goal of managing costs more effectively and maximizing returns by accelerating the recovery of reserves. The successful technological development that supports this objective enhances the economics of all suitable prospects, but it also accelerates the exhaustion of reserves wherever applied. The implied “cushion” of spare productive capacity has shrunk correspondingly. Thus, sudden surges in demand now must be accommodated by a relatively smaller capacity margin. If the incremental demand is considerable, as happened in 2000 when an unprecedented combination of factors led to a large demand increase, the supply system may approach its productive limits, and price surges can result.

The ability to mitigate or avoid sustained price increases depends on the potential to expand supply capacity. When prices rise suddenly after a period of low prices, the industry will tend to have a portfolio that includes marginal or previously subeconomic prospects. At the then higher prices, a number of those projects may become economically attractive. Some ready prospects may be implemented quickly, but they tend to be ones that were previously uneconomical due to limited production potential. The marginal prospects generally yield relatively smaller production flows and do not increase aggregate supplies greatly until large numbers of them have been brought into production. More sizable deposits or additional exploration effort involve difficulties and delays that prolong the lag time between first actions and actual production. Chapter 2 provides more detailed discussion of this aspect of natural gas supplies.

Short-term price cycles seem inevitable in competitive markets for natural gas. When the industry operates at close to full capacity, small changes in supply and/or demand can cause significant market pressures and substantial price increases or decreases. A key facet of competition is the necessity for economic decisionmaking with regard to tradeoffs between lowering costs and maintaining supply capability to meet expected demand. When actual demand exceeds expectations, considerable strain may be imposed on the industry. The industry responds by increasing supply, but when the limits of supply capacity are approached, price increases are likely.

The capacity to consume or supply natural gas is based on an accumulation of capital that reflects the outcome of a series of investment decisions over an extended period. Significant changes in the capital stock are not achieved rapidly. The supply difficulties in 2000 do not seem to have been caused by a fundamental inadequacy, such as a serious resource limitation, because prices have since returned to levels consistent with the pattern of 1998-1999. The supply situation was at least partly attributable to the relatively low prices for an extended period that preceded the 2000-2001 spikes. Low prices led to expansion of gas-consuming equipment while discouraging further development of production prospects and needed infrastructure. Actual consumption levels were affected by weather conditions and by prices for competing fuels that limited natural gas consumption to levels that were disproportionately low relative to the underlying capacity. Unless market prices balance contemporaneous supply and demand and also provide the stimulus appropriate to maintain that balance at stable prices, recurrence of sustained price spikes is likely.

The significant price reductions and record storage additions that have occurred since May 2001 indicate that the U.S. natural gas market contains the self-correcting mechanisms associated with well-functioning markets. This bodes well for the market outlook in the short term and beyond. Domestic resources are expected to be substantial, and the potential for foreign supplies is limited only by the U.S. capacity to import, which is expandable. On the other hand, the market experience in 2000-2001 indicates that natural gas prices can be vulnerable to short-term fluctuations in market conditions.

2. Mid-Term Natural Gas Supply: Analysis of Federal Access Restrictions

Introduction

A substantial amount of the Nation's natural gas resources underlie Federal lands and / or environmentally sensitive areas where access is limited by Federal statutes, rules, and regulations. Most of the onshore natural gas resources subject to Federal access limitations are located in the Rocky Mountain region. Significant portions of the Rocky Mountain resources are either off limits to exploration and development or subject to Federal lease stipulations[52] when production is allowed. Offshore natural gas resources in the Pacific, Atlantic, and Eastern Gulf of Mexico Outer Continental Shelf (OCS)[53] are also subject to Federal access limitations. Except for a relatively small tract in the Eastern Gulf of Mexico, these areas are legally off limits to exploration and development under existing Federal moratoria.

Reducing Federal access restrictions in the Rocky Mountains and OCS is expected to increase the available resource base by 87 trillion cubic feet, which would expand the available lower 48 resource base from 1,190 to 1,277 trillion cubic feet, a 7-percent increase. Reducing Federal access restrictions does not imply that all land restrictions would be removed. An estimated 62.5 trillion cubic feet of natural gas resources would remain unavailable for development, for example, in National Parks, National Monuments, and wilderness and roadless areas, as well as areas currently precluded by the effect of statutes and regulations.

Onshore Resources

Of the natural gas resources yet to be developed in the onshore United States, those subject to Federal access restrictions are located primarily in the Rocky Mountain region.[54] The Rocky Mountain region contains approximately 37 percent (293 trillion cubic feet) of the remaining unproved technically recoverable natural gas resources in the lower 48 onshore United States (Figure 10).[55,56] In the onshore, only the Gulf Coast Region at 24 percent approaches in magnitude this region's endowment. Most of the Rocky Mountain resources, however, need to be subjected to a significant degree of stimulation (e.g., hydraulic fracturing) or other "unconventional" production techniques in order to attain sufficiently economic levels of production. These unconventional natural gas resources consist of three basic types: gas in low permeability sandstones (tight sands), gas in low permeability shales (gas shales), and gas in coal formations (coalbed methane). Tight sands account for 65 percent of the unproved natural gas resources in the Rocky Mountains. The rest of the Rocky Mountain unconventional resources, 16 percent of the region's total resources, are mostly coalbed methane and a small

[52]Lease stipulations are mandated modifications to a lease. As defined in *Uniform Format for Oil and Gas Lease Stipulation*, prepared by the Rocky Mountain Regional Coordinating Committee (March 1989): "Stipulations are conditions, promises, or demands to be part of a lease when the environmental and planning record demonstrates the necessity for the stipulations. Stipulations, as such, are neither 'standard' nor 'special,' but rather a necessary modification of the terms of the lease. In order to accommodate the variety of resources encountered on Federal lands, stipulations are categorized as to how the stipulation modifies the lease rights, not by the resource(s) to be protected. What, why, and how this mitigation / protection is to be accomplished is determined by the land management agency through land use planning and National Environmental Policy Act (NEPA) analysis."

[53]The offshore area of the United States extending outward beyond the 3 nautical mile line in the Atlantic and Pacific and the 9 nautical mile line in the Gulf of Mexico makes up the Outer Continental Shelf.

[54]The Rocky Mountain oil and gas supply region includes Arizona, Colorado, Idaho, Montana, Nevada, western New Mexico, North Dakota, South Dakota, Utah, and Wyoming.

[55]Unproved resources are those resources that are estimated to exist but are not yet proven to exist. Proved reserves of natural gas as of December 31 of the report year are the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proven if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and / or electric or other log interpretations. Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1999*, DOE / EIA-0216(99) (Washington, DC, December 2000), p. 154.

[56]Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability. These are oil and natural gas resources that may be produced at the surface from a well as a consequence of natural pressure within the subsurface reservoir, artificial lifting of oil from the reservoir to the surface, and the maintenance of reservoir pressure by fluid injection. These resources are generally conceived as existing in accumulations of sufficient size to be amenable to the application of existing recovery technology. Source: U.S. Geological Survey, National Oil and Gas Resource Assessment Team, *1995 National Assessment of United States Oil and Gas Resources*, U.S. Geological Survey Circular 1118 (1995), p. 5.

amount of gas shales. The remaining 19 percent of total unproved resources in the Rocky Mountain Region are conventional natural gas resources, primarily in higher permeability sandstone or carbonate reservoirs.

The 293.3 trillion cubic feet of unproved Rocky Mountain natural gas resources are subject to a variety of access restrictions (Table 4). Of that amount, 33.6 trillion cubic feet is officially off limits to either drilling or surface occupancy (No Access - Legal). Included in this category are those areas where drilling is precluded by statute (e.g., national parks and wilderness areas) and by administrative decree (e.g., "wilderness re-inventoried areas" and "roadless areas"). Also included are those areas of a lease where surface occupancy is prohibited by stipulation to protect identified resources such as the habitats of endangered species of plants and animals.

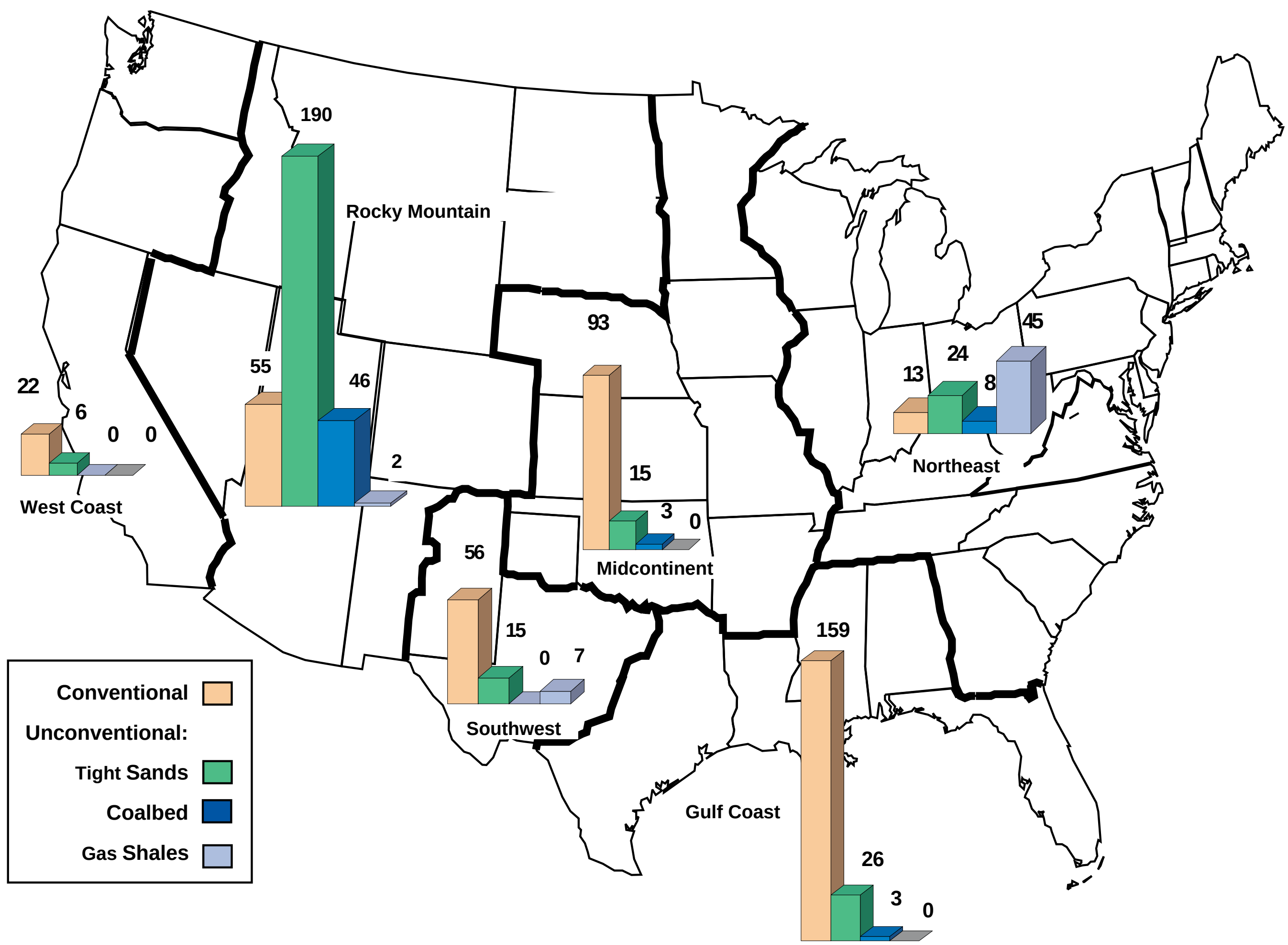
Table 4. Unproved Natural Gas Resources in the Rocky Mountain Region as of January 1, 2000
(Trillion Cubic Feet)

Access Status	Conventional	Unconventional	Total
No Access - Legal	3.4	30.2	33.6
No Access - De Facto	—	57.7	57.7
Access - Lease Stipulated	16.1	34.7	50.8
Access - Standard Lease Term . .	35.9	115.3	151.2
Total	55.4	237.9	293.3

Note: Includes both associated-dissolved and nonassociated gas resources.

Source: Advanced Resources, International, "Technical Memorandum: Federal Lands Access for the NEMS Oil and Gas Supply Module," FE 30 Support Contract: DE-AC01-99FE65607 (July 2001).

Figure 10. Unproved Technically Recoverable Natural Gas Resources in the Onshore Lower 48 States as of January 1, 2000
(Trillion Cubic Feet)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

An additional 57.7 trillion cubic feet of the resources are judged to be currently *de facto* off limits[57] because of the prohibitive effect of compliance with environmental and pipeline regulations created under such laws as the National Historic Preservation Act, the National Environmental Policy Act, the Endangered Species Act, the Air Quality Act, and the Clean Water Act[58] (No Access - De Facto).

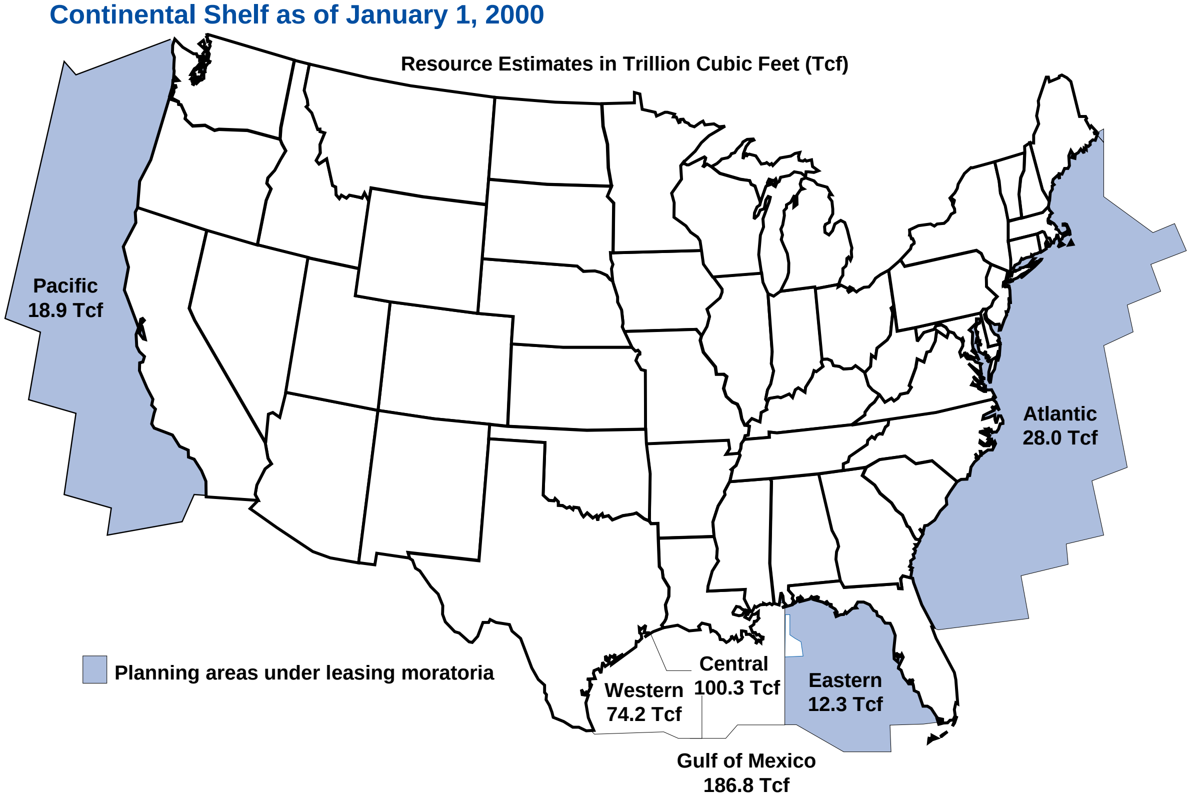
Of the 202 trillion cubic feet of resources that are accessible, 50.8 trillion cubic feet are located in areas where Federal lease stipulations affect the costs and timing of development (Access - Lease Stipulated). The lease stipulations are set by either the U.S. Bureau of Land Management or the U.S. Forest Service. The remaining 151.2 trillion cubic feet of unproved Rocky Mountain natural gas resources are located either on Federal land without lease stipulations or on private land and are fully accessible subject to standard lease terms with no lease stipulations (Access - Standard Lease Terms). These 151.2 trillion cubic feet of resources are currently available for development.

Offshore Resources

The offshore natural gas resources most affected by Federal access restrictions are located in certain areas of the lower 48 OCS. The lower 48 OCS is estimated to contain substantial resources of natural gas, including both gas in gas fields (nonassociated) and gas in oil fields (associated-dissolved). Based on the 2000 assessment by the Minerals Management Service (MMS) of the U.S. Department of Interior, the mean estimate of undiscovered, technically recoverable natural gas resource as of January 1, 2000, in the lower 48 OCS is 233.7 trillion cubic feet[59] (Figure 11), including resources in areas that are currently inaccessible.

The Gulf of Mexico area contains 80 percent of the U.S. OCS undiscovered natural gas resources. Of the estimated 186.8 trillion cubic feet of remaining undiscovered natural gas in the Gulf of Mexico, approximately 70 percent can be found in water depths greater than 200 meters. Associated-dissolved gas accounts for 9 percent of the undiscovered resources in shallow waters (less

Figure 11. Mean Estimates of Undiscovered, Technically Recoverable Resources in the U.S. Outer Continental Shelf as of January 1, 2000



Source: U.S. Department of Interior, Minerals Management Service, *Outer Continental Shelf Petroleum Assessment, 2000*, mean estimates with values adjusted to reflect 1999 new field discoveries.

[57] Advanced Resources, International, "Technical Memorandum: Federal Lands Access for the NEMS Oil and Gas Supply Module," FE 30 Support Contract: DE-AC01-99FE65607 (July 2001).

[58] Advanced Resources, International, *Federal Lands Analysis, Natural Gas Assessment, Southern Wyoming and Northwestern Colorado: Study Methodology and Results* (May 2001); National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand* (December 1999).

[59] Undiscovered resources are unproved resources that are estimated to exist in fields that have yet to be discovered.

than 200 meters) and almost 32 percent of the resources in deep waters. The vast majority (93 percent) of the undiscovered resources in the Gulf of Mexico are in the Western and Central planning areas.

Access to offshore natural gas resources is restricted primarily by Federal moratoria on leasing. The MMS is responsible for overseeing the development of resources in the OCS as directed in the Outer Continental Lands Act of 1953 (OCLA). The MMS announces which leases will be available for sale under a 5-year leasing schedule in order to manage the resources in the OCS in an orderly manner; however, not all areas are open for leasing. The planning areas in the Pacific, Atlantic, and most of the Eastern Gulf of Mexico are withdrawn under Section 12 of the OCLA through June 30, 2012. As a result of this legislation, 58.2 trillion cubic feet of the undiscovered, technically recoverable natural gas resources in the OCS are currently unavailable: 18.9 trillion cubic feet in the Pacific, 28 trillion cubic feet in the Atlantic, and 11.3 trillion cubic feet in the Eastern Gulf of Mexico. The MMS sale 181 area, which contains 1 trillion cubic feet of technically recoverable resources, is the only part of the Eastern planning area that is not excluded under Section 12. The remaining 175.5 trillion cubic feet of fully accessible lower 48 OCS resources are located almost entirely in the Western and Central Gulf of Mexico.

Even if the Federal moratoria were lifted and offshore leasing activity resumed in Federal waters, States and nongovernmental entities in opposition to offshore oil and gas development could use other legal means to preclude or at least limit the extent of Federal offshore oil and gas exploration and production. Although the States and local governments can not directly prohibit the physical development of offshore oil and gas resources in Federal waters, it would be possible to make their development considerably more expensive. A primary method for accomplishing this would be to preclude or limit the development of oil and gas infrastructure within the jurisdiction of the State and local governments by use of restrictive zoning. The oil and gas infrastructure necessary to develop Federal offshore energy resources include many elements, such as harbor facilities, onshore separation and treatment plants, oil refineries, and pipelines for transporting the crude oil and natural gas onshore. For the purposes of this analysis it is assumed that local infrastructure issues and other potential non-Federal impediments would be overcome if Federal access restrictions were lifted, and that oil and gas development would proceed at rates similar to those seen in the early development of currently accessible areas.

Analysis of Access Restrictions

Representation in the National Energy Modeling System

As requested by the Secretory of Energy, the Energy Information Administration (EIA) has conducted an analysis of the impact of removing Federal restrictions on access to natural gas resources, using mid-term forecasts from the National Energy Modeling System (NEMS). The reference case for the analysis is the reference case from EIA's *Annual Energy Outlook 2002* (*AEO2002*),[60] which assumes that the current Federal restrictions on access to natural gas resources will remain in place throughout the forecast period (2001-2020). Federal access limitations in the Rocky Mountain region are represented in the NEMS Oil and Gas Supply Module (OGSM) by removing inaccessible resources from the module's resource base and by assuming cost increases and timing delays for developing resources in areas where Federal lease stipulations are routinely imposed. Access limits on the restricted portions of the OCS are represented in the OGSM by not allowing any exploration or development in those areas throughout the forecast period.

Access Restrictions in the Rocky Mountain Region

The treatment of access restrictions in the Rocky Mountain region in the reference case varies by access status. Resources located on land that is legally inaccessible are removed from the model's operative resource base. Resources located in areas that are *de facto* inaccessible because of environmental and pipeline regulations are initially removed from the model's resource base but are made available gradually over the forecast period to reflect the tendency of technological progress to enhance industry's ability to overcome difficulties in complying with the restrictions. Resources that are accessible but located in areas that are subject to lease stipulated access limitations are accounted for by two adjustments: (1) exploration and development costs are increased by 6 percent[61] to reflect the increased costs that access restrictions generally add to a project; and (2) 2 years are added to the assumed schedules for projects in restricted areas to simulate the delay usually incurred as a result of efforts to comply with the access restrictions.

The following assumptions were used in developing analysis cases to evaluate the potential effect of increased access to natural gas resources in the Rocky Mountains on the mid-term outlook for U.S. natural gas supply:

[60]Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), web site www.eia.doe.gov/oiaf/aeo/.

[61]This is consistent with the cost factor adjustment utilized in the 1999 National Petroleum Council Study, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand* (December 1999), Volume II, Task Group Reports.

- The status of the 33.6 trillion cubic feet of resources that are currently *legally inaccessible* remains inaccessible in the future.

- The initial amount of *de facto inaccessible* resources is decreased from 57.7 trillion cubic feet to 28.9 trillion cubic feet to reflect a greater flexibility in the administration of Federal environmental and pipeline regulations, making an additional 28.8 trillion cubic feet immediately accessible. The remaining 28.9 trillion cubic feet is made accessible incrementally throughout the forecast.

- Current Federal lease stipulations are removed, and it is assumed that future Federal leases will not have such stipulations, rendering 50.8 trillion cubic feet of the Rocky Mountain resources 6 percent less costly to develop and with 2 years less time.

With these assumptions, 230.8 trillion cubic feet, instead of the current 202 trillion cubic feet, of unproved natural gas resources in the Rocky Mountain Region would be immediately accessible, and 50.8 trillion cubic feet of that 230.8 trillion cubic feet would be less expensive and take less time to find and develop than in the reference case.

Access Restrictions in the Outer Continental Shelf

Although existing moratoria on leasing in the OCS are scheduled to expire in 2012, the *AEO2002* reference case assumes that the moratoria will again be reinstated, as they have been in the past. Current rules as to access are therefore assumed to prevail for the remainder of the forecast period, and no exploration or development is allowed in areas currently closed to leasing under Federal moratoria.

The following assumptions were used in developing analysis cases to assess the potential impact of opening access to areas currently under leasing moratoria in the lower 48 OCS:

- Leases in areas currently under moratoria are included in the 2007-2012 lease sale.

- Assumptions about exploration, development and production of economical fields (drilling schedules, costs, platform selection, reserves-to-production ratios, etc.) are based on data for similar fields, both in depth and size, in the Western Gulf of Mexico.

- An additional 2-year delay between exploration and development is assumed to be required to get the necessary infrastructure in place in the Atlantic area.

With these assumptions, 58.2 trillion cubic feet is added to the amount of accessible undiscovered, technically recoverable natural gas resources in the lower 48 OCS, raising the total to 233.7 trillion cubic feet from the current level of 175.5 trillion cubic feet.

Higher Demand for Natural Gas

If natural gas consumption were higher in the future than projected in the reference case, the higher level of demand would likely stimulate more rapid development and production of natural gas resources, including the additional resources assumed to be made available in the Rocky Mountain and OCS areas in the analysis cases that reduce Federal access restrictions. A carbon dioxide emissions limit case was used in this analysis to examine the effects of higher demand for natural gas. Because the carbon content of coal is the highest among the fossil fuels, electricity generators are expected to reduce their coal use to meet a cap on carbon dioxide emissions, and natural gas consumption is expected to increase as a result.

The carbon dioxide emissions limit case includes all the assumptions of the *AEO2002* reference case and, in addition, assumes that carbon dioxide emissions from electricity generators will be capped at 7 percent below their 1990 levels beginning in 2007. The cap is phased in over a 5-year period, beginning in 2002, reaching 440 million metric tons carbon equivalent (the 1990-7% level) in 2007. In this case, carbon dioxide emissions from the electricity generation sector are projected to be lower than in the reference case by an average of 229 million metric tons carbon equivalent per year from 2002 through 2020, and total U.S. natural gas consumption in 2020 is projected to be 2.9 trillion cubic feet higher than in the reference case.

Analysis Cases

To examine the sensitivity of natural gas supply and prices to the lifting of Federal access restrictions, four analysis cases were employed. In three access cases, Federal access restrictions were assumed to be lifted for either the OCS or the Rocky Mountains, or for both regions, with all other assumptions the same as those in the reference case. In the fourth access case, Federal access restrictions were assumed to be lifted for both the OCS and the Rocky Mountains in an environment of higher natural gas demand resulting from the imposition of a carbon dioxide emissions limit. In total, six cases were used, as summarized below:

- **Reference case:** A policy-neutral case developed by EIA for the *AEO2002* under the assumption that all laws, including Federal access restrictions, remain in force as currently enacted.

- **Carbon dioxide emissions limit case:** Includes all the assumptions of the reference case, as well as a cap on carbon dioxide emissions from the electricity generation sector that results in higher demand for natural gas.

- **Rocky Mountain access case:** Includes all the assumptions of the reference case, but reduces

Federal access restrictions in the Rocky Mountain region.

- **OCS access case:** Includes all the assumptions of the reference case, but opens currently inaccessible areas of the OCS.
- **Rocky Mountain and OCS access case:** Includes all the assumptions of the reference case, but reduces Federal access restrictions in the Rocky Mountain region and opens currently inaccessible areas of the OCS.
- **Rocky Mountain and OCS access case with carbon dioxide emissions limit:** Includes all the assumptions of the carbon dioxide emissions limit case, but reduces Federal access restrictions in the Rocky Mountain region and opens currently inaccessible areas of the OCS.

Table 5 shows the assumed levels of accessible unproved, technically recoverable natural gas resources that would be available for development in the Rocky Mountain and OCS areas in each of the six cases.

Results

In the analysis cases for this study, the lifting of Federal access restrictions makes more resources available for conversion into producing reserves and enables less costly, more timely production of resources in areas that are currently open to development. All other things being equal, this should tend to increase the potential supply of natural gas and put downward pressure on average wellhead prices. The model results, summarized in Table 6, reflect those expectations.

Reference Case

In the reference case, natural gas consumption is projected to grow by an average of 2.1 percent per year, from 22.5 trillion cubic feet in 2000 to 33.8 trillion cubic feet in 2020. The highest projected growth is in the electricity generation sector, from 4.2 trillion cubic feet in 2000 to 10.3 trillion cubic feet in 2020. By 2020, electricity generation becomes the largest consumer of natural gas. In comparison, the largest current gas consumer, the industrial sector, is expected to increase from 8.4 trillion cubic feet in 2000 to 10.1 trillion cubic feet in 2020.

To meet the growth in natural gas consumption, both domestic production and imports are projected to increase. Dry gas production increases by 2.0 percent per year in the reference case from 19.0 trillion cubic feet in 2000 to 28.5 trillion cubic feet in 2020. Most of the increase is from lower 48 onshore production, which is projected to increase from 13.3 trillion cubic feet in 2000 to 21.1 trillion cubic feet in 2020. Lower 48 offshore production is projected to increase from 5.3 trillion cubic feet in 2000 to 6.8 trillion cubic feet in 2020. Alaskan gas production is projected to increase only slightly, from 0.4 trillion cubic feet in 2000 to 0.6 trillion cubic feet in 2020.

Projected increases in gas imports are expected to come primarily from Canada and from overseas in the form of liquefied natural gas (LNG). Net Canadian gas imports are projected to increase from 3.5 trillion cubic feet in 2000 to 5.1 trillion cubic feet in 2020, and net LNG imports are projected to increase from 0.2 trillion cubic feet in 2000 to 0.8 trillion cubic feet in 2020. The LNG projection is based on the expectation that the four existing LNG terminals—Cove Point, Maryland; Elba Island, Georgia; Everett, Massachusetts; and Lake Charles, Louisiana—will be operating at full capacity (80 percent of design capacity) by 2010.

From 1995 to 2000, the natural gas wellhead price averaged $2.38 per thousand cubic feet (2000 dollars). Relative to that average, the natural gas wellhead price is projected to increase at an average rate of 1.6 percent per year in the reference case, to $3.26 per thousand cubic feet in 2020. Increasing prices reflect the rising demand for natural gas and the progression of the discovery process to smaller, deeper conventional fields and to unconventional natural gas fields, all of which are more costly to develop on a per unit of production basis.

Table 5. Accessible Unproved, Technically Recoverable Natural Gas Resources in the Rocky Mountain and OCS Areas in Six Cases as of January 1, 2000
(Trillion Cubic Feet)

Resource	Reference Case	Carbon Dioxide Emissions Limit Case	Analysis Cases			
			Rocky Mountain Access	OCS Access	Rocky Mountain and OCS Access	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit
Rocky Mountains	202.0	202.0	230.8	202.0	230.8	230.8
OCS Undiscovered . .	175.5	175.5	175.5	233.7	233.7	233.7

Note: In the cases that assume the continuation of current Federal restrictions on access to Rocky Mountain natural gas resources, 50.8 trillion cubic feet of the 202 trillion cubic feet of Rocky Mountain resources incur increased costs and development time due to Federal lease stipulations. In the cases with increased Rocky Mountain access, the stipulations are assumed not to be in force, so that the development costs and delays are reduced.

Sources: Table 4 and Figures 10 and 11.

Table 6. Summary of Model Results for Access Restrictions on Federal Lands, 2010, 2015, and 2020

Key Results for Natural Gas	2000	Projections: Reference Case	Projections: Carbon Dioxide Emissions Limit Case	Analysis Cases: Rocky Mountain Access[a]	Analysis Cases: OCS Access[a]	Analysis Cases: Rocky Mountain and OCS Access[a]	Analysis Cases: Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit
		2010					
Lower 48 Cumulative Reserve Additions from 2001 (Trillion Cubic Feet)	—	219	226	222	221	224	232
Lower 48 Cumulative Production from 2001 (Trillion Cubic Feet)	—	207	215	207	207	207	215
Lower 48 End-of-Year Reserves (Trillion Cubic Feet)	168	174	174	177	177	179	179
Lower 48 Production (Trillion Cubic Feet)	18.6	22.9	24.3	23.1	23.0	23.1	24.4
Lower 48 Average Wellhead Price (2000 Dollars per Thousand Cubic Feet)	3.60	2.85	3.81	2.80	2.83	2.78	3.69
U.S. Consumption (Trillion Cubic Feet)	22.6	28.1	30.4	28.2	28.2	28.2	30.5
		2015					
Lower 48 Cumulative Reserve Additions from 2001 (Trillion Cubic Feet)	—	350	365	354	355	360	377
Lower 48 Cumulative Production from 2001 (Trillion Cubic Feet)	—	330	341	331	331	332	345
Lower 48 End-of-Year Reserves (Trillion Cubic Feet)	168	182	186	185	187	191	195
Lower 48 Production (Trillion Cubic Feet)	18.6	25.8	25.6	25.9	25.9	26.0	26.3
Lower 48 Average Wellhead Price (2000 Dollars per Thousand Cubic Feet)	3.60	3.07	3.37	3.04	3.04	3.02	3.23
U.S. Consumption (Trillion Cubic Feet)	22.6	31.3	34.0	31.4	31.4	31.5	34.3
		2020					
Lower 48 Cumulative Reserve Additions from 2001 (Trillion Cubic Feet)	—	491	510	499	499	506	527
Lower 48 Cumulative Production from 2001 (Trillion Cubic Feet)	—	466	477	468	467	470	485
Lower 48 End-of-Year Reserves (Trillion Cubic Feet)	168	188	196	193	194	199	204
Lower 48 Production (Trillion Cubic Feet)	18.6	27.9	27.9	28.1	28.1	28.5	29.0
Lower 48 Average Wellhead Price (2000 Dollars per Thousand Cubic Feet)	3.60	3.26	3.72	3.20	3.22	3.15	3.57
U.S. Consumption (Trillion Cubic Feet)	22.6	33.8	36.7	33.9	33.9	34.2	37.3

[a]The Rocky Mountain Access, OCS Access, and Rocky Mountain and OCS Access cases do not include the carbon dioxide emissions limit.

Note: The values shown for 2000 represent the most current natural gas data available when this report was published. The values shown for 2000 in Appendixes B and C represent the most current natural gas data available when the model runs were produced.

Sources: **2000 Lower 48 Reserves:** Energy Information Administration, *Advance Summary: Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 2000 Annual Report*, DOE/EIA-0216(2000)Advance Summary, p. 5, web site www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/advanced_summary_2000/adsum2000.pdf. **2000 Lower 48 Production and U.S. Consumption:** Energy Information Administration, *Natural Gas Annual 2000*, DOE/EIA-0131(00) (Washington, DC, November 2001). **2000 Lower 48 Wellhead Price:** Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, ACCRM.D111101A, ACCOFF.D111101A, ACCREF.D111101A, and ACCHDEM.D111101A.

Carbon Dioxide Emissions Limit Case

A carbon dioxide emissions limit favors less carbon-intensive fuels. By 2020, coal consumption in the carbon dioxide emissions limit case is 50 percent lower than projected in the reference case, and natural gas consumption rises to 36.7 trillion cubic feet, as compared with 33.8 trillion cubic feet in the reference case. Natural gas consumption in the electricity generation and industrial sectors is projected to increase to 11.9 and 10.4 trillion cubic feet, respectively, in 2020, compared with 10.3 and 10.1 trillion cubic feet in the reference case.

The impact of the carbon dioxide emissions limit on the projected mix of natural gas supplies depends on the time frame. In 2010, higher natural gas demand in the carbon dioxide emissions limit case results primarily in greater production from lower 48, onshore wells (17.7 trillion cubic feet, compared with 16.5 trillion cubic feet in the reference case). Conventional and unconventional lower 48 natural gas production levels are also higher than projected in the reference case in 2010 at 8.5 and 7.7 trillion cubic feet, respectively. After 2010, new LNG terminals and an Alaskan gas pipeline to the lower 48 States are expected come into operation. By 2020, much of the incremental gas supply required in the carbon dioxide emissions limit case is projected to be met by shipments of Alaskan gas to the lower 48 States (1.6 trillion cubic feet[62]) and by higher net LNG imports (almost 1.4 trillion cubic feet[63]). As LNG and Alaskan gas become increasingly available, they displace the need for lower 48 production. Consequently, lower 48 production in the carbon dioxide emissions limit case in 2020 is projected to be only 60 billion cubic feet more than in the reference case, at 27.9 trillion cubic feet.

A cyclic price trend is apparent in the carbon dioxide emissions limit case after 2005 (see Figure 13), primarily due to the initial surge in natural gas demand that results from the imposition of a carbon dioxide emissions limit (see Chapter 4 for analysis of potential cyclic price behavior in the U.S. natural gas market). Between 2005 and 2007, natural gas consumption is projected to increase by more than 1 trillion cubic feet per year. At that rate of increase in natural gas consumption there would be a relative scarcity of supply and reserves, causing natural gas prices to increase to relatively high levels. Because of the delay between price increases and the availability of new natural gas supplies, natural gas prices would have to remain at a high enough level for a long enough period of time to bring forth sufficient supplies to satisfy the higher projected level of demand.

After 2010, the initial surge in natural gas demand is projected to taper off, and the growth in demand returns to a rate that is closer to that projected in the reference case. At this point, natural gas prices are expected to begin declining, both because of the more moderate growth in demand and because of a relative surplus of supply. The relative supply surplus would be created by the delay between changes in price and changes in wellhead supply. Essentially, high levels of gas drilling activity would continue even after natural gas prices have fallen, causing prices to fall even further. Eventually, however, lower drilling activity would cause natural gas reserves to be depleted, and as a result, prices are projected to begin increasing again after 2015 as natural gas supplies become relatively more scarce.

Wellhead natural gas prices in 2020 are higher in the carbon dioxide emissions limit case than in the reference case, because the higher production levels earlier in the forecast move the industry further along the depletion curve for conventional gas (making it more costly), and because onshore, high-cost unconventional gas production makes up a larger portion of lower 48 production. By 2020, the lower 48 average wellhead price for natural gas in the carbon dioxide emissions limit case is $3.72 per thousand cubic feet, $0.46 per thousand cubic feet higher than projected in the reference case.

Rocky Mountain Access Case

Of the 57.7 trillion cubic feet of Rocky Mountain natural gas resources assumed to be *de facto* inaccessible in the reference case, 28.8 trillion cubic feet is assumed to be accessible in the Rocky Mountain access case as a result of increased flexibility in the administration of Federal environmental and pipeline regulations. In addition, with the removal of Federal lease stipulations, 50.8 trillion cubic feet of the Rocky Mountain natural gas resources is no longer assumed to incur higher development costs and deferred income due to drilling delays. The larger, more profitable resource base results in increased reserve additions, which enlarge the reserve base and increase productive capacity relative to the reference case projection. With more natural gas available at lower prices, projected lower 48 natural gas production in 2020 is 245 billion cubic feet higher than in the reference case, at an average wellhead price that is 6 cents per thousand cubic feet lower.

OCS Access Case

In the OCS access case, access is allowed to the currently inaccessible areas of the Atlantic, Pacific, and Eastern Gulf of Mexico OCS, adding 58.2 trillion cubic feet to the approachable, technically recoverable U.S. natural gas resource base. As a result, cumulative lower 48 natural gas reserve additions are projected to be 8 trillion cubic

[62]Total Alaskan gas production is 2.2 trillion cubic feet, with 0.6 trillion cubic feet being consumed in Alaska.

[63]Both expansion at existing facilities and construction of new regasification terminals in the United States are needed to reach the net LNG import level of 1.35 trillion cubic feet per year.

feet greater by 2020 than projected in the reference case. From the higher reserve level in the OCS access case, 236 billion cubic feet more production is projected in 2020 than in the reference case, at an average wellhead price that is 4 cents per thousand cubic feet lower.

Rocky Mountain and OCS Access Case

The Rocky Mountain and OCS access case combines increased access to the Rocky Mountains with the opening up of the OCS. As a result, 87 trillion cubic feet of currently inaccessible natural gas resources become available for exploration and development, and 50.8 trillion cubic feet of resources become less costly to develop with a shorter lead time. With the larger, less costly resource base, cumulative lower 48 reserve additions throughout the forecast are projected to be 15 trillion cubic feet higher than in the reference case. Consequently, the remaining lower 48 natural gas reserves in 2020 are projected to be 11 trillion cubic feet higher than in the reference case. With this improved reserve position, natural gas production in 2020 is projected to be 578 billion cubic feet higher than in the reference case, and the average wellhead price is projected to be 11 cents per thousand cubic feet lower.

Rocky Mountain and OCS Access Case with Carbon Dioxide Emissions Limit

This analysis case uses the same access assumptions as the Rocky Mountain and OCS access case, with the higher natural gas demand projected in the carbon dioxide emissions limit case. The higher demand requirements exert upward pressure on the wellhead price to the extent that some of the fields that are expected to be accessible but not profitable in the Rocky Mountain and OCS access case become profitable. Because the newly profitable fields contain some of the larger resource deposits in the previously inaccessible areas, the differences in results between this case and the carbon dioxide emissions limit case tend to be greater than the differences between the Rocky Mountain and OCS access case and the reference case.

Lower 48 cumulative reserve additions are projected to be 17 trillion cubic feet greater in 2020 in the Rocky Mountain and OCS access case with carbon dioxide emissions limit than in the carbon dioxide emissions limit case. Natural gas production is projected to be 1.1 trillion cubic feet higher in 2020, and the average wellhead price is projected to be 15 cents per thousand cubic feet lower than in the carbon dioxide emissions limit case. With the higher levels of demand (and higher production) in both cases, end-of-year reserves in 2020 are projected to be 8 trillion cubic feet greater in the Rocky Mountain and OCS access case with carbon dioxide emissions limit than in the carbon dioxide emissions limit case—3 trillion cubic feet smaller than the projected difference in 2020 end-of-year reserves (11 trillion cubic feet) between the Rocky Mountain and OCS access case and the reference case.

Comparison of production projections (Figure 12) shows the effect of increased access to be greater in a higher demand environment. The higher demand for natural gas that results from an assumed cap on carbon dioxide emissions from the electricity generation sector causes upward pressure on prices. At higher price levels, substantially more of the newly accessible deposits become profitable to develop. Over the last 10 years of the forecast, a period during which increased access to the OCS is fully implemented, the cumulative difference in production between the Rocky Mountain and OCS access case with carbon dioxide emissions limit and the carbon dioxide emissions limit case is projected to reach 7 trillion cubic feet, as compared with a projected differential of 3 trillion cubic feet between the Rocky Mountain and OCS access case and the reference case over the same period.

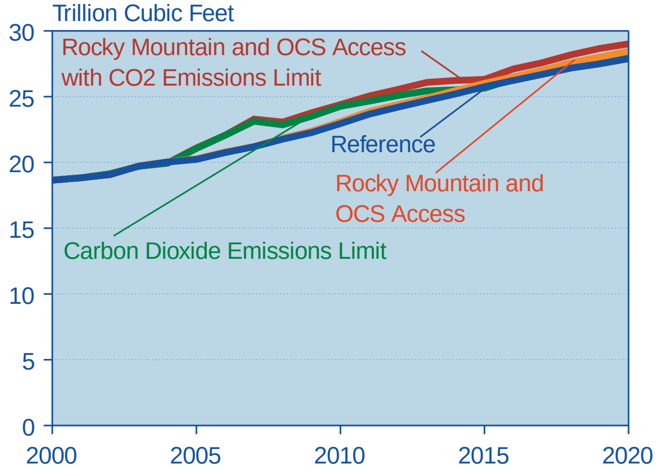
The projections for wellhead natural gas prices show a similar trend among the cases with different demand levels (Figure 13). In the two cases with a cap on carbon dioxide emissions, the price increases sharply from 2004 to 2007, then begins to decline as drilling increases induced by the higher prices enhance productive capacity through additions to the reserve base. In addition, higher projected prices in the two cases with higher natural gas demand result in the opening of a pipeline to provide natural gas supplies from the north slope of Alaska, as well as increases in imports of liquefied natural gas (LNG)—from new and existing LNG import terminals—both of which put downward pressure on prices in the later years of the forecast. Under these conditions, increased access to Rocky Mountains and OCS natural gas resources is projected to put further downward pressure on prices. In the latter half of the forecast (2011 to 2020), the average lower 48 wellhead price is projected to average 14 cents lower in the Rocky Mountain and OCS access case with carbon dioxide emissions limit than in the carbon dioxide emissions limit case. In comparison, the average lower 48 wellhead price in the Rocky Mountain and OCS access case is projected to average 8 cents lower than in the reference case over the same period.

Conclusion

The lifting of Federal access restrictions is projected to have an impact on U.S. natural gas supply and prices in the mid-term, and the projected impact is even greater in the high price environment of the carbon dioxide emissions limit case. When Federal access restrictions are assumed to be lifted to varying degrees in the reference case environment, the average wellhead price of natural gas in 2020 is projected to be lower by 4 to 11 cents per thousand cubic feet, and domestic natural gas production in 2020 is projected to be higher by 236 to 578 billion cubic feet, than projected in the reference case (which assumes the continuation of current access restrictions).

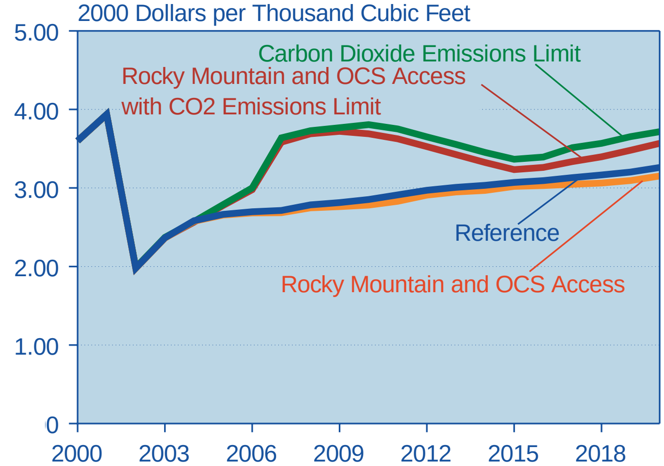
By comparison, in the Rocky Mountain and OCS access case with carbon dioxide emissions limit, the average wellhead price of natural gas in 2020 is projected to be lower by 15 cents per thousand cubic feet, and domestic natural gas production in 2020 is projected to be higher by 1,078 billion cubic feet, than projected in the carbon dioxide emissions limit case (which also assumes the continuation of current access restrictions). Further, the *cumulative* impact in the Rocky Mountain and OCS access case with carbon dioxide emissions limit is even more dramatic: wellhead natural gas prices from 2010 to 2020 are projected to average 14 cents per thousand cubic feet lower than projected in the carbon dioxide emissions limit case, and cumulative production is projected to be 7 trillion cubic feet greater over the 10-year period.

Figure 12. Lower 48 Natural Gas Production in Four Cases, 2000-2020



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, ACCREF.D111101A, and ACCHDEM.D111101A.

Figure 13. Average Lower 48 Natural Gas Wellhead Price in Four Cases, 2000-2020



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, ACCREF.D111101A, and ACCHDEM.D111101A.

3. Mid-Term Natural Gas Supply: Analysis of LNG Imports

Introduction

During the winter and spring of 2001, when U.S. natural gas prices reached record highs and strong growth in natural gas consumption was being forecast both worldwide and in the United States, many analysts and investors expressed the opinion that liquefied natural gas (LNG) might in the future provide a much larger share of U.S. natural gas supply. Given the natural gas consumption forecast of 33.8 trillion cubic feet in 2020 in the Energy Information Administration's (EIA's) *Annual Energy Outlook 2002* (*AEO2002*),[64] existing design capacity of just over 1 trillion cubic feet per year at the four U.S. terminals[65] and proposed expansion of about 0.4 trillion cubic feet per year would be able to meet about 3.3 percent of projected total demand in 2020.

Costs throughout the LNG supply chain have fallen, making it a much more attractive economic investment, especially for suppliers who believe that prices will reach and be sustained at a level high enough to make LNG competitive. Although natural gas prices have fallen considerably in the past few months,[66] many suppliers are still confident that prices will increase and remain above the level at which they feel LNG is competitive.

International supplies are plentiful, but the capacity of U.S. import facilities limits the amount of gas that can be received and regasified. There are currently three facilities in operation, at Everett, Massachusetts; Lake Charles, Louisiana; and Elba Island, Georgia. A fourth facility at Cove Point, Maryland, was scheduled to reopen within the next year, but the opening may be delayed as a result of rehearing requests received by the Federal Energy Regulatory Commission (FERC).[67] The FERC will make a decision on December 13, 2001, on whether to allow a rehearing.

Numerous additional facilities are under consideration, but siting an LNG receiving terminal can be a formidable task. Aside from the facility site requirements, local opposition (often referred to as the NIMBY[68] factor) can be close to insurmountable and is likely to be the most important factor in whether a facility is built in a particular location. A method for circumventing this obstacle is to site facilities to serve U.S. markets outside U.S. borders, such as in Baja California (Mexico) or in the Bahamas. While this may reduce the NIMBY opposition, it will not eliminate it entirely; local Baja residents have voiced resistance to the siting of an LNG facility in the Baja region.

While the international supply needed to satisfy the potential U.S. demand for LNG is available, worldwide LNG demand is also seeing strong growth, which could lead to competition for available supplies and higher prices. Another potential limiting factor for U.S. LNG import growth is tanker availability. Although tanker construction costs have fallen, shipping cost is still a major component of LNG prices. Because most LNG tankers are built within the context of long-term purchase commitments, there are few tankers available to handle short-term purchases, even though short-term sales are becoming a larger proportion of the LNG market.

Recent Worldwide LNG Developments

The growth in demand for natural gas worldwide is outpacing the demand for any other hydrocarbon fuel. This is due to a number of factors, including price, environmental concerns, fuel diversification and/or energy security issues, deregulation of both natural gas and electricity markets, and overall economic growth. In

[64] Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001).

[65] Sustainable capacity is closer to 80 percent of design capacity and varies because of differences in utilization rates, down time for maintenance, etc.

[66] According to EIA's November 2001 *Short-Term Energy Outlook*, first-quarter wellhead prices averaged $6.37 per thousand cubic feet, second quarter $4.55, third quarter $3.06, and fourth-quarter prices are expected to average $2.70 (all in 2001 dollars).

[67] Security and safety concerns raised in the wake of the September 11th terrorist attacks regarding Cove Point's proximity to the Calvert Cliffs nuclear facility have prompted the rehearing requests.

[68] NIMBY is the acronym for "Not In My Back Yard." It is used when residents of an area are not necessarily opposed in general to a particular facility being built, but they want it to be somewhere other than in their neighborhood, city, or even State.

EIA's *International Energy Outlook 2001* (*IEO2001*), worldwide natural gas use is projected to almost double between 1999 and 2020, growing from 84 trillion cubic feet to 162 trillion cubic feet. The largest increases in natural gas use are expected in Central and South America and in developing Asia. The largest increases in industrialized countries are expected in North America (primarily the United States) and Western Europe.

Given the anticipated growth in world demand for natural gas, it will be necessary to develop new natural gas fields and infrastructure to assure adequate supplies. As of January 1, 2001, 10 countries held 77 percent of the world's natural gas reserves, with Russia, Iran, and Qatar accounting for more than 55 percent (Table 7).

Natural gas reserves that would be extremely expensive to transport through pipelines to potential markets are commonly referred to as "stranded reserves." Stranded reserves are expected to be a major source of natural gas for world LNG trade. It has been estimated that stranded reserves make up about 50 percent of the natural gas reserves held by the top 10 countries shown in Table 7 and between 2,755 and 3,350 trillion cubic feet worldwide.[69]

Qatar began exporting LNG in 1997 and currently has two export terminals and an additional one in the planning stage. Iran has two terminals in planning stages, currently scheduled to be operational in 2005 or 2006.

Table 7. World Natural Gas Reserves by Country as of January 1, 2001
(Trillion Cubic Feet)

Country	Reserves	Percent of World Total
World	**5,278**	**100.0**
Top 10 Countries	4,043	76.6
Russia	1,700	32.2
Iran	812	15.4
Qatar	394	7.5
Saudi Arabia	213	4.0
United Arab Emirates	212	4.0
United States	167	3.2
Algeria	160	3.0
Venezuela	147	2.8
Nigeria	124	2.3
Iraq	110	2.1
Rest of World	1,235	23.4

Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 98, No. 51 (December 18, 2000), pp. 121-124.

Nigeria began exporting LNG in 1999, and Venezuela has plans to begin in 2003. Indonesia, Algeria, Malaysia, and the United Arab Emirates, four of the five largest exporters of LNG in 1999 (Qatar is the fifth), have been exporting LNG for close to 20 years, and Australia has been exporting LNG since 1989. Considerable expansion is planned at existing liquefaction facilities, and at least 15 new projects are under consideration.[70] Although it is the newest project in the industry, future LNG production from Trinidad's three trains[71] will make Atlantic LNG the fifth largest exporter of LNG in the world.[72]

Given this distribution of resources, an increase in the amount of natural gas traded across international borders will be inevitable. With many natural gas resources located far from demand centers, LNG will become progressively more attractive as a method of transport. Although in 1999 barely 20 percent of the natural gas consumed worldwide was traded across international borders, 22 percent of that was in the form of LNG. LNG will both satisfy some of the increasing demand and provide source countries a means of monetizing these otherwise stranded natural gas reserves.

One factor contributing to the world growth in the LNG trade is the declining cost structure of all phases of the supply chain, which has allowed the cost at which LNG becomes economic to fall within the year 2001 range of natural gas prices. With new suppliers coming on board, competition has forced cost-cutting measures and price reductions. Liquefaction costs between 1996 and 2000 averaged $230 per ton, compared with $560 per ton between 1986 and 1990. Between 1996 and 2000 the cost of a new tanker dropped by approximately 30 percent.[73] The construction costs for regasification terminals have seen similar decreases. In addition to the numerous planned expansions and new facilities for liquefaction, the tanker fleet is expanding. At the end of 2000, the fleet stood at 127 ships, with 22 on order and 7 under option. More than 20 new LNG receiving terminals are either planned or proposed, and more than 10 are under either renovation or construction.

LNG Technology and Economics

Although worldwide natural gas supplies for LNG facilities are abundant and can be produced inexpensively, the processing and transportation equipment is capital intensive and highly specialized, requiring hundreds of millions of dollars of investment for each new facility.

[69] Zeus Development Corporation, *2001 World LNG/GTL Review*, p. iv.

[70] Statistics on LNG trade are from D. Bamber, ed., *Fundamentals of the Global LNG Industry* (London, UK: Petroleum Economist, Ltd., March 2001), pp. 166-167.

[71] A "train" is the term used in the industry to describe a complete processing facility.

[72] Atlantic LNG Media Release (June 26, 2001).

[73] Cost information is based on D. Bamber, ed., *Fundamentals of the Global LNG Industry* (London, UK: Petroleum Economist, Ltd., March 2001), p. 11.

For each cubic foot of natural gas delivered to end users, less than 30 percent of the cost is for the commodity itself. The balance reflects the costs of processing and transportation. LNG project costs can vary significantly because of site-specific construction costs. LNG projects comprise several distinct elements, each of which is necessary to implement a successful project:

- **Abundant low-cost natural gas reserves.** A successful LNG project must have enough proved reserves of natural gas available to support liquefaction capacity for the life of the plant (20+ years). In addition, production costs (including applicable production taxes levied by the host government) need to be low (typically, less than $1 per thousand cubic feet, and preferably on the order of $0.50 per thousand cubic feet).

- **A liquefaction facility, including a jetty and loading facilities for LNG tankers.** The liquefaction plant is typically the most expensive element of an LNG project. The cost depends on a host of site-specific factors, including the project's scale, with larger projects having lower unit costs. Operating costs are relatively minor. Liquefaction is a very energy-intensive process, with typically about 8 to 9 percent of the plant's input used as plant fuel.

- **LNG tankers.** Each project requires several dedicated LNG tankers. These are among the most complex and expensive merchant ships ever built because of their double hulls and special cryogenic lining. Each new 135,000 cubic meter (3 billion cubic foot) capacity tanker costs approximately $260 million. The tanker's LNG cargo is kept cool by evaporating a fraction of the cargo ("boiloff") and burning it as boiler fuel. Typically, 0.15 to 0.25 percent of the cargo is consumed per day, during which the tanker will travel about 480 nautical miles.

- **Regasification plant.** LNG can be unloaded only in specialized terminals, which typically include a jetty and unloading facilities, LNG storage equal to at least a single tanker cargo, regasification facilities, and connections to pipelines. The cost of the regasification terminal varies with capacity, local construction costs, and the amount and type of site preparation costs. Regasification plant costs are typically considerably lower than liquefaction plant costs. Regasification energy requirements consume a further 1.5 percent of the delivered LNG. The marginal cost of either utilizing excess capacity at an existing regasification plant with excess capacity or expanding the capacity of an existing plant would be far lower than the cost of building a new greenfield facility.

The large capital costs of each link in an LNG project imply that projects can be undertaken in general only by organizations with sufficient financial capacity. Under the traditional LNG project structure, successful LNG projects required the cooperation of the host government (where the natural gas resources are located), the entity that owns the natural gas rights (private or state), the government of the consuming country, consuming organizations (national or private electric utilities, gas companies, etc.), and a host of specialized organizations, including shipyards, financiers, tanker operators, construction companies, and process technology licensors. In the past, protracted negotiations were often needed to reach agreement regarding the distribution of the costs, the benefits, and the considerable risks associated with the project. This project structure may be evolving, however, as a result of the proliferation of spot market trading of LNG in recent years.

No LNG project is likely to proceed unless the developers receive some assurance that they will be able to earn an acceptable return on their investments. A successful LNG project requires a price that is low enough to motivate consumers to use large volumes of natural gas, yet still high enough to persuade developers and borrowers to actually build the project. One risk that cannot be ignored is the likely formation of an LNG cartel, given that so few countries control such a large portion of the world's stranded natural gas reserves, and its power to affect LNG prices. Although spot sales are on the rise, LNG developers will seek (but not always find) long-term contracts for their product at a price that is sufficient to cover their capital costs and service debts even in a lower-than-anticipated energy price environment. It is also common for consumers to be offered or to take an equity stake in LNG projects, so as to encourage a common interest among the buyers and the sellers.

With natural gas consumption growing rapidly throughout the world, there are many potential and expanding LNG markets. Countries that are potential LNG markets are those with significant demand for natural gas (enough to make LNG trade economically viable) that cannot be satisfied by their own indigenous production or by pipeline imports from neighboring countries, because of a lack of reserves or lack of infrastructure to get reserves to the demand centers. Receiving terminals for LNG are being constructed or considered in numerous locations, including China, India, Korea, Japan, Southern Europe, Latin America, and recently the United States.

When locations for new LNG import facilities are proposed, several tangible and intangible factors must be considered. The major tangible factors include water depth (especially the depth of the channel to the jetty and the potential for silting), availability of reasonably priced large industrial tracts near deep water, and availability of a right-of-way for the pipeline (in high-density areas, rights-of-way may already exist). These three criteria must be satisfied before any location can receive further consideration. In addition, the site needs to have both proximity and access to markets and, of course, access to LNG supplies.

The primary elements of the LNG receiving facility itself are berths for unloading the LNG tankers, storage tanks to receive the ship's cargo, and vaporizers to regasify the LNG for distribution to market centers through natural gas pipelines. Other elements include site improvements and roads, buildings and services, and miscellaneous components including piping, controls, and utilities. The actual construction time averages about 3 years. In the United States, the approval process for a new site, which usually takes from 18 to 24 months, can be extended considerably if there is strong NIMBY opposition.

The U.S. Market for LNG

LNG in the United States has a sketchy past. Because of rising natural gas prices in the 1970s, LNG project sponsors anticipated large profits and constructed the four U.S. LNG receiving terminals in existence today. Dreams of high profits never materialized, however, because natural gas prices began a precipitous decline after their 1983 peak, and all but one of the four were mothballed. The facility at Everett, Massachusetts, remained in operation only because it was located in a heavily concentrated market center where demand was high and the cost of bringing conventional supplies to market by pipeline was high enough to exceed the cost of LNG.[74] In 1989, the Lake Charles, Louisiana, facility was reactivated,[75] mainly to receive spot cargos.

For close to 20 years, LNG was not considered to be an economical source of natural gas. As a result of the high 2000-2001 prices and the growing demand for natural gas, interest in LNG has renewed to the point that not only are the other two facilities, at Elba Island, Georgia, and Cove Point, Maryland, reopening (Elba reopened in October 2001), but at least 13 new facilities have been proposed to serve U.S. markets (Table 8). Some of the parties proposing the terminals readily indicate that although prices have fallen since their proposals were first put forth, they expect future prices to be in a range where LNG is economical relative to competing supply sources. Although LNG was in the past used mainly for peaking purposes, the expanding use of natural gas for electricity generation potentially makes it a less seasonal commodity. Thus, if the economics of LNG become more favorable in the United States, higher utilization of LNG facilities can be expected, just as pipeline capacity utilization is increasing.

Existing LNG Receiving Terminals

Everett Marine Terminal. The Everett Marine Terminal has a design capacity of approximately 160 billion cubic feet per year,[76] and plans have been announced to add another 200 billion cubic feet per year capacity. Everett is located northwest of central Boston, Massachusetts, on the Mystic River. Construction was completed in 1971, and it has been in operation since that time. It has one unloading berth and two aboveground storage tanks. One tank has a 60,000 cubic meter capacity and the other has a 95,000 cubic meter capacity, for a total of 155,000 cubic meters. Assuming the average LNG ship cargo is 130,000 cubic meters (net), the tanks can hold 1.19 ship cargos.[77] In addition to supplying natural gas to the Algonquin pipeline, the facility has the capability to load 1 million gallons per day or more of LNG into trailers for over-the-road transport to other facilities.

The original vaporizer configuration consisted of two trains, with six vaporizers per train. The vaporizers are direct fired with hot water exchangers. Everett can also send out between 90 and 100 million cubic feet per day by truck. The facility has been expanded several times with pipeline connections and increased truck loading capability. Although the facility operators are planning to expand the vaporizing capabilities by adding additional submerged combustion vaporizers, the limited availability of land (and corresponding limits of exclusion zones) precludes additional tankage, which creates a cap on facility growth.

Cove Point Import Terminal. The Cove Point facility is has a design capacity of 365 billion cubic feet per year. Cove Point is located on the Chesapeake Bay at Cove Point in Lusby, Maryland, about 50 miles south of Washington, DC. It was constructed in 1978 and operated as an LNG import and storage facility from 1978 to 1980,

[74] Not only is the Boston market about as far as one could get from the major sources of U.S. conventional natural gas supplies, the geology of the region (i.e., granite) precludes the construction of nearby underground storage facilities. As a result, the Algonquin Gas Pipeline typically operated at a 40 percent annual load factor. Since storage availability serves to levelize the load for pipelines and thus reduce overall transportation costs, the lack of these facilities put the area at a distinct disadvantage.

[75] The reopening of Lake Charles was one condition agreed to with Algeria as part of the Panhandle Eastern bankruptcy agreement.

[76] See web site www.NEGA.com/industry_trends/about_LNG0901.html.

[77] Ships are typically characterized by their cargo volume in cubic meters of LNG. Most current ships are in the 125,000 to 138,000 cubic meter gross volume range, and some 144,000 cubic meter ships are anticipated in the future. A net cargo offloaded of 130,000 cubic meters is equivalent to 2.87 billion cubic feet of methane (assuming a heat rate of 1,009 Btu per cubic foot, lower than the heat rate of most LNG delivered to U.S. markets, which is closer to 1,100 Btu per cubic foot). If cargos have heavier components, the number of cubic feet and heating value will be greater and the total amount delivered will be greater. Tanks are also characterized by liquid volume—barrels in the United States and cubic meters internationally. A 1 billion cubic foot tank is 284,778 barrels or 45,278 cubic meters. Tanks range from 0.5 to 3.5 billion cubic feet. Most new terminal tanks are in the 2 to 3.5 billion cubic feet size, and larger tanks are probable in the future.

before being shut down. Since 1995, it has been providing peak shaving services to customers in the mid-Atlantic and Southeastern regions. The new operator, Williams Companies, had been granted permission by the FERC to return it to an LNG import and storage facility. As a result of national security and safety concerns, raised in the wake of the September 11th terrorist attacks, regarding Cove Point's proximity to the Calvert Cliffs nuclear facility, however, the FERC is considering whether to grant or deny rehearing requests that have been submitted.[78]

Cove Point has two unloading berths capable of handling large LNG ships and four aboveground storage tanks. All four storage tanks have a capacity of 59,630 cubic meters, or 238,520 cubic meters total. This equals 1.83 ship cargos, assuming a net cargo of 130,000 cubic meters per ship. Total receiving capacity is 435 billion cubic feet (19.8 million cubic meters) per year, or about 150 cargos. The facility has 12 vaporizers (10 fired vaporizers and 2 non-fired using waste heat). Williams received plans to add one additional 160,000 cubic meter tank and recommission idle vaporizers. Cove Point is surrounded by open land and considerable future expansion would be technically possible, but expansion is limited by an agreement with the Sierra Club that prohibits expansion beyond current boundaries.[79]

Table 8. Proposed Sites for U.S. LNG Import Terminals

Location	Proposed Capacity (Billion Cubic Feet per Year)	Company
Bahamas to Florida[a]	250	Enron
Bahamas to Florida[a]	200	El Paso
Radio Island, NC	100	El Paso
Tampa, Florida	200	BP
Gulf of Mexico Offshore	365	Texaco
Brownsville, Texas	365	Cheniere
Freeport, Texas	365	Cheniere
Sabine Pass, Texas	365	Cheniere
Hackberry, Louisiana	275	Dynergy
Baja California, Mexico[a]	250	El Paso
New Brunswick, Canada[a]	275	Irving Oil
Altamira, Mexico[a]	475	El Paso/Shell
Baja California, Mexico[a]	365	CMS/Sempra
Total Proposed	**3,850**	

[a]Proposed LNG plants outside the United States, with natural gas to be transported by pipeline to U.S. markets.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, Oil and Gas Division.

Elba Island Import Terminal. The Elba Island facility has five submerged-type vaporizers with a total vaporization design capacity of approximately 160 billion cubic feet per year. The operators have announced plans to replace the existing vaporizers with five larger submerged combustion vaporizers, which will give the terminal a total design capacity of 292 billion cubic feet per year.[80] Located on Elba Island, downriver of Savannah, Georgia, on the Savannah River. It was completed in 1978 and operated until 1980, when it was shut down. It was recently recommissioned, and received its first cargo in October 2001. Presently, it consists of one berth and three above ground storage tanks. All three tanks have a 60,000 cubic meter capacity, or 180,000 cubic meters total. This equals 1.38 ship cargos, assuming a 130,000 million cubic meter net cargo per ship. Elba Island also has a trailer unloading capacity of 10 million cubic feet per day.

Lake Charles Import Terminal. The Lake Charles import terminal has seven submerged-type vaporizers with a design capacity of 365 billion cubic feet per year. Plans have been announced to increase the vaporization capacity by adding another 73 billion cubic feet per year.[81] Other expansion plans are believed to include the addition of another berth for unloading LNG ships. The Lake Charles facility is located on the Calcasui River, south of Lake Charles, Louisiana. It was completed in 1982 and operated until 1983. It was reopened in 1989 and has remained in operation. It has one berth and three aboveground tanks. Each of the Lake Charles tanks has a 95,400 cubic meter capacity, for a total of 286,200 cubic meters. Lake Charles has a maximum receiving capacity of 165 billion cubic feet (7.5 million cubic meters). Based on a net cargo of 130,000 cubic meters, the tanks will hold 2.20 cargos, or about 58 cargos per year.

Potential Sites for New LNG Facilities

North Carolina. El Paso Natural Gas has announced a lease on Radio Island in Morehead City, North Carolina, as the potential site for a 100 billion cubic feet per year LNG facility. Morehead City has deep water and Radio Island is near the channel entrance, in protected water, making it a suitable site for docking large LNG vessels. The primary disadvantage in North Carolina is that the

[78]Web site www.williams.com/gaspipeline/htm/releases/2001/013001.htm.

[79]In 1972, the Maryland Conservation Council and the National Sierra Club went to court to stop Columbia LNG Corporation from constructing the Cove Point LNG import terminal. The issue was one of proper use of a prime natural area that had been designated by the State as a State park. The case was settled out of court. Provisions of the agreement permitted Columbia to proceed with its plans, but required major modifications to the design of its facility to protect the beach and the appearance of the shoreline. These modifications limit physical expansion onto surrounding land.

[80]Web site www.epenergy.com/press/.

[81]Web site www.panhandlecompanies.com/term_lng.asp.

major transmission pipelines run through the western half of the State, and a rather long right-of-way must be acquired to connect to the system. Fortunately, North Carolina is largely rural and the right-of-way can avoid heavily populated areas and the accompanying problems. Nevertheless, local opposition to the proposed terminal has been strong.

Florida. Florida has 14 deepwater ports, but only Tampa (and possibly Jacksonville) has adequate depth for a large LNG tanker. Florida is also a rapidly growing market. Florida's governor has opposed the President's energy policy regarding the exploration and development of oil resources within 100 miles of the coast, and public opposition to any new energy facility in the State should be expected. Additionally, most of Florida's coastline is developed, and a large undeveloped site within a mile of deep water would be difficult to find.

El Paso Natural Gas and Enron have independently announced plans to investigate building a facility in the Bahamas, about 30 miles off the Florida coast, either shore-based or offshore. An underwater pipeline would connect the facility to existing pipelines in Florida and the environmental impact in the United States would be minimal. The facility sizes proposed are 200 and 250 billion cubic feet per year, respectively. British Petroleum (BP) is also considering a 200 billion cubic feet per year facility in Tampa.

Gulf of Mexico. Texaco has recently announced plans to investigate the feasibility of developing an offshore LNG facility with a 365 billion cubic feet per year capacity in the Gulf of Mexico and connecting it to one or more of the existing pipelines in the Gulf. The facility (or facilities) would be a deepwater floating terminal, similar in concept to the Louisiana Offshore Oil Port (LOOP). The hurdle to overcome in this case is regulatory. Discussions with United States Coast Guard (USCG) officials revealed that the existing regulations for this type of facility cover only oil ports; no regulations exist for LNG facilities, and the USCG would require the promulgation and oversight of such regulations. This also raises a jurisdictional issue for the FERC, which has jurisdiction up to the 200-mile limit. Although several studies have indicated that the technical problems are manageable, such an offshore floating terminal would be a first. The ship-to-terminal offloading method has created considerable discussion.

Texas and Louisiana. The coast of Texas and Louisiana has several potential sites for an LNG facility. Lake Charles, Louisiana, already has an LNG facility, and Dynegy has announced plans to construct a 275 billion cubic feet per year LNG facility at its LPG facility in Hackberry, Louisiana. Like other LNG import waterways, Lake Charles has regulations in place for LNG ship transit. Texas ports, such as Houston and Corpus Christi, are already heavily industrialized with oil terminals, and an LNG terminal would not be out of place; however, finding a large, available tract of land may be the greatest obstacle. The Houston Ship Channel is already congested with traffic, and LNG tankers would not be welcomed in the ship safe zones utilized elsewhere. Port Arthur also has some possibilities. Texas and Louisiana also have several existing pipelines, making acquisition of a suitable right-of-way less of a problem in this region. Cheniere Energy has announced plans to construct three LNG receiving terminals, each with a 200 billion cubic feet per year initial capacity, along the Texas Gulf Coast.

Southern California and Mexico. Southern California has many logistical considerations in common with Florida. It has several deepwater ports capable of handling LNG ship traffic, but the combination of existing industrial development and a high population density would make siting an LNG facility difficult. The ports that would be most attractive have already been developed, and their utilization would require innovative approaches. Additionally, the citizenry and government are very protective of the environment and resistant to this type of project. California also has the history of an unsuccessful LNG import project in the late 1970s.[82]

El Paso has announced plans to build a 250 billion cubic feet per year LNG facility in Mexico and has secured property in Rosarito. The plan is to construct the facility in Mexico and connect it to an existing pipeline near the U.S. border to serve the California natural gas market. El Paso will avoid the NIMBY concerns in California but will be subject to Mexican property laws for siting and right-of-way, as well as approval from Mexico's energy regulatory commission, the Commission Reguladora D'Energie (CRE). There are no ideal ports in northern Baja California; therefore, the siting and design will not be straightforward.

New Regasification Facility Cost Considerations

The costs for an LNG import terminal depend on several variables. Some have minor impacts and others very significant impacts on cost. Those that have a major impact on costs are storage capacity installed, geology of the area (soil stability and seismic activity), labor and construction costs for the area, and the marine environment (proximity to deep water, need for dredging and/or

[82]In December, 1977, the DOE approved, subject to renegotiation of certain pricing provisions, a proposal to import 200 billion cubic feet of Indonesian LNG annually for 20 years into a facility to be constructed on a 210 acre site in Oxnard, California, that would be owned and operated by Western LNG terminals. Due to difficulties in negotiating new pricing provisions, regulatory delays, environmental concerns, and changes in the marketplace, the sponsors filed notice with the DOE in 1985 formally canceling the project.

breakwater). Other factors include public opposition and permitting. Other elements that affect total cost are trestle length, sendout, site improvements, roads, buildings, services, and miscellaneous expenses such as piping, controls, and utilities.

In addition to new facility construction, additional capacity can be obtained through the expansion of existing facilities. Most facilities are constructed with an initial operating capacity and built-in expansion potential that can be obtained by increasing any one of a number of factors that limit throughput, including number of berths, size of the receiving tanks, capacity of the vaporizers, and capacity of the sendout lines.

Since there are so many variables that contribute to the cost of building and operating a receiving terminal, a number of assumptions regarding facility configuration and site characteristics were made in developing the costs of new facilities for EIA's analysis. From these assumptions, generic capital costs for a basic LNG import terminal, as well as multipliers to account for unique features of each potential location,[83] were developed. Assumptions regarding the regasification facilities include:

- Two 140,000 cubic meter containment tanks are used for storage. The basis of this assumption is the rule of thumb to have two times ship volume of storage for the facility.
- The trestle length is 300 feet. Trestle length could vary significantly; costs are approximately $140,000 per foot.
- The site has adequate soil for construction of roads and building foundations. No piling is required.
- The area is not seismically active.
- Sendout is 0.5 billion cubic feet per day.
- No dredging is required.

The regional cost multipliers are based on wage differentials, land costs, and other factors that vary by region. They are used to increase the accuracy of the assumed construction costs when applied to different regions. The regional cost multipliers are shown in Table 9.

The major costs in operating a facility are personnel and power. Personnel, the largest single expenditure, is a fixed cost; and power is variable relative to sendout. The estimates used assume that administrative functions are provided by parent company personnel rather than by personnel directly associated with the LNG import facility.

The main operating costs of the facility can be divided into fixed and variable costs. The fixed costs are payroll, maintenance, insurance, and taxes. Payroll is estimated at $2.8 million per year for approximately 22 employees (at Gulf Coast wages), and maintenance costs account for an additional $2.8 million per year. Taxes and insurance are estimated at $5.7 million. This is a rough estimate because taxes (and potential tax abatements) vary widely by location, and insurance costs are, in part, a function of the operator's safety record. Variable costs include fuel, electricity, chemicals, and other consumables. Electricity consumption is estimated to be approximately 480 kilowatthours per day.

Means of Facility Expansion

In addition to new facility construction, additional capacity can be obtained through the expansion of existing facilities. Most facilities are constructed with an initial operating capacity and built-in expansion potential that can be obtained by adjusting any one of a number of factors that limit throughput, including the following. The import terminal operator has some control over most of these factors in that additions may be made to the facility or operations may be tailored to allow for mitigating factors.

Number of berths. A typical ship unloading requires about a 24-hour turnaround time, broken down as follows:

- 4 hours for customs, immigration, custody transfer measurements, connecting the unloading arms, and cooldown
- 12 to 14 hours unloading
- 6 to 8 hours for final custody transfer measurements and calculations, disconnecting unloading arms, provisioning, and deberthing.

Table 9. Assumed Regional Cost Multipliers for U.S. LNG Terminal Construction and Expansion

Area	Cost Multiplier
New York/New Jersey	1.32
Delaware River/ South Jersey	1.10
Chesapeake Bay Area	0.83
North Carolina	0.77
Florida	0.83
Gulf of Mexico	0.85
Texas/Louisiana	0.83
Southern California	1.08
Mexico	0.80
Washington/Oregon	1.04

Note: The specifications for the generic terminal were not designed with any particular location in mind; there is thus no region with a multiplier of 1.

Source: Costs developed by Project Technical Liaison (PTL) Associates under contract to the Energy Information Administration.

[83]The costs were developed by Project Technical Liaison (PTL) Associates under contract to the Energy Information Administration.

A reasonable scheduling assumption for one berth is one ship every 3 days. For a 2.84 billion cubic feet cargo, this is essentially a 0.9 billion cubic feet per day terminal capacity limitation resulting from a single berth. There will be times when there will be delays such that the shipping, inventory, and sendout logistics must be flexible to accommodate occasional delays. Alternative mooring availability is also a consideration.

Contractual arrangements for shipping. Establishing a shipping schedule well in advance (i.e., for a 1-year period) will allow the inventory management necessary to assure adequate cargo arrivals and a minimum of ship demurrage[84] while awaiting receiving tank space. Scheduling becomes more complicated where more than one ship or shipper is utilized. If there is more than one export terminal as the source, then inevitably there will be times when two ships arrive on the same day and other times when there is twice the average time between ships.

Number of LNG sources and spot cargo activity. If more than one export source of LNG supplies an import terminal, the ship arrival schedule will be much more erratic with occasional to frequent situations where two cargos arrive nearly at the same time. This implies that there will be an extended period with fewer (or no) cargos. Spot cargos are becoming more available but require some time to negotiate. Spot cargos have little flexibility in schedule, either from the supply or ship availability standpoint. In order to accommodate spot cargos, the import terminal must have the ability to take an extra ship out of normal sequence.

Size of receiving tanks. The receiving tankage must have the capacity to take the ship's cargo. There must also be additional volume to accommodate schedule and sendout variability. As a rule of thumb, receiving tankage should be at least two times cargo volume, or about 6 billion cubic feet. Additional volume may be useful and / or economic to facilitate erratic ship scheduling, spot cargos, variable sendout rates, and peak demand opportunities. Because ship storage costs about 5 or 6 times the equivalent on-shore storage, the best overall economic result is achieved by buffering logistic variability with additional tankage at the receiving terminal. Additional storage at the receiving terminal also assists in responding to peak demand markets and general logistics management.

Capacity of vaporizers. The sendout pumps and vaporizers must meet the maximum contractual sendout rate. It is common practice to have at least one spare unit for reliability and maintenance functions. Typically, additional vaporizers can be added, although air emission permits can be a problem. Most tanks will have provision for additional or larger pumps. Additional booster pumps for pipeline pressure can typically be added, but installed standby units are advisable and common practice.

Variability in sendout. Generally speaking, as long as the receiving terminal's storage is large enough, variability in daily sendout rates will affect only the pumps and vaporizers and will not affect the upstream shipping and receiving functions. Short-term sendout variability problems arise when the sendout rate is interrupted such that there will not be receiving tank space for the next ship. Such a situation can occur if the primary customer is a power plant and the power plant is taken offline. A provision in the contract to allow any excess gas to be sold to other customers in the market may alleviate high inventory problems. Long-term variability problems arise when there is a consistent sendout rate either above or below the contractual supply amount. This will result in either shipping delays with demurrage or very low inventories awaiting ship arrival.

Capacity of sendout lines. The sendout pipelines must have the capacity to take away the maximum sendout rate consistent with maintaining the nominal throughput. Pipeline capacity can often be increased by compressor stations and line looping, but these functions may not be within the control of the terminal operator. For example, the Cove Point sendout line currently has a maximum capacity of about 1.2 billion cubic feet per day and is a limiting factor for the current configuration.

Capacity of local and regional system. The local and regional areas served by the terminal need to absorb the throughput. For example, the Distrigas terminal in Boston has a large market in the immediate area, whereas the Elba Island terminal is relatively remote from concentrated usage areas except Savannah.

Schedule discretion in truck deliveries. An import terminal can facilitate inventory management if there are discretionary markets available. If LNG is delivered by truck to offsite peak-shaving plants, the schedule is typically set so that the peak-shaving tank is filled by the beginning of the heating season. When the deliveries are actually made is inconsequential to the peak-shaving plant, so the import terminal can manage inventory by scheduling the trucking to occur during times in the summer when LNG inventories are high. The ability to have certain customers that are willing to take gas at the terminal's request serves a similar inventory management function. Short-term sales have been made straightforward with the advent of natural gas marketing, and if the import terminal operator is also a natural gas supplier, this may be relatively easy.

[84]Extra days beyond the days agreed upon to unload the cargo are called days of demurrage. The term is also applied to a charge for delaying a steamer beyond a stipulated period.

Analysis of LNG Imports

Analysis Cases

To analyze the sensitivity of domestic natural gas production and prices to increased LNG import terminal capacity, two analysis cases were used in addition to the *AEO2002* reference case and the carbon dioxide emissions limit case (described in Chapter 2, "Analysis of Access Restrictions," pages 20-24). All the cases used the same assumptions regarding existing and potential future LNG regasification capacity. Because there is considerable uncertainty surrounding the various costs that make up the delivered cost of LNG, the two LNG analysis cases were developed to examine the impact of those costs on the expansion of existing and construction of new LNG receiving terminals. Both cases were based on the carbon dioxide emissions limit case.

The high LNG cost case assumes that LNG production costs are double the costs assumed in the reference case by 2020, that the rate of return on LNG tankers is 20 percent rather than the 15 percent assumed in the reference case, and that the rate of return on liquefaction plants is 12 percent rather than the 10 percent assumed in the reference case. The low LNG cost case assumes that LNG production costs are 50 percent lower than in the reference case by 2020, that the rate of return on LNG tankers is 10 percent rather than the 15 percent assumed in the reference case, and that the rate of return on liquefaction plants is 8 percent rather than the 10 percent assumed in the reference case.

Results

The differences in assumptions for the cases are reflected in the projected minimum regional import prices needed to trigger expansion and/or construction of new facilities. The trigger prices represent summations of the five major costs in the LNG chain: production, liquefaction, transportation, regasification, and receiving terminal site-specific costs such as permitting, special land and waterway preparation and/or acquisitions, and regulatory costs. Because LNG is used primarily to serve local markets in the vicinity of the receiving terminal, it competes with regional prices rather than national average wellhead prices. The regional trigger prices assumed in the reference case and the two LNG analysis cases are shown in Table 10. Projections for domestic natural gas production, consumption, and prices and for LNG imports are summarized in Table 11.

Table 10. Assumed LNG Trigger Prices in Three Cases

Region	Reference	High LNG Cost	Low LNG Cost
New England	4.00	4.81	3.59
Mid-Atlantic	3.88	4.67	3.45
South Atlantic	3.80	4.41	3.19
Florida	3.96	4.57	3.35
East South Central . .	3.90	4.64	3.42
West South Central . .	3.93	4.67	3.45
Northwest	4.82	5.43	4.20
California	4.55	5.16	3.93

Note: LNG cost assumptions in the carbon dioxide emissions limit case are the same as those in the reference case.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, HCSTHDEM.D111201A, and LCSTHDEM.D111201B.

The variation of LNG costs, and thus the availability of more LNG, affect the demand for natural gas (Figure 14). The impacts on natural gas consumption in the high and low LNG cost cases are seen towards the end of the forecast, with the spread reaching 0.6 trillion cubic feet by 2020. The corresponding difference in the wellhead price in 2020 is $0.16 per thousand cubic feet, indicating that the availability of more LNG reduces prices (Figure 15). The largest price spread ($0.21 per thousand cubic feet) occurs in 2017 and represents a difference of about 6 percent between the two analysis cases.

The projected prices in the high LNG cost case are sufficiently high to make expansion at existing facilities over what has already been announced and construction of new facilities uneconomical. As a result, the 2020 projection for LNG import capacity in the high LNG cost case is the same as in the reference case, and LNG imports are the same in the two cases throughout the forecast (Figure 16).

Domestic natural gas production shows a maximum variation across the cases of 0.5 trillion cubic feet in 2015, but the gap narrows to 0.2 trillion cubic feet by 2020 as more LNG capacity becomes available (Figure 17). In 2020, the difference in LNG imports between the two LNG analysis cases exceeds the difference in production by 50 percent. Thus, LNG in these cases not only makes up for the difference in production but also displaces some Canadian imports (Figure 18).

Although additional expansion of LNG import capacity beyond the expansion plans already announced is not projected to occur in the reference case or in the high LNG cost case, additional expansion is projected in the carbon dioxide emissions limit case and the low LNG cost case. In the carbon dioxide emissions limit case, prices reach a level that triggers expansion at existing U.S. receiving facilities and new facility construction, and net LNG imports are projected to increase to 1.35 trillion cubic feet, or 3.7 percent of demand, by 2020. Beginning in 2010, when natural gas wellhead prices peak at $3.81 per thousand cubic feet, expansion begins at existing facilities beyond what has already been announced, and some new construction begins in the South Atlantic region. Partly in response to the availability of the new supply, average lower 48 wellhead prices fall back to $3.37 per thousand cubic feet by 2015. With

Table 11. Summary of Model Results for LNG Imports, 2010, 2015, and 2020

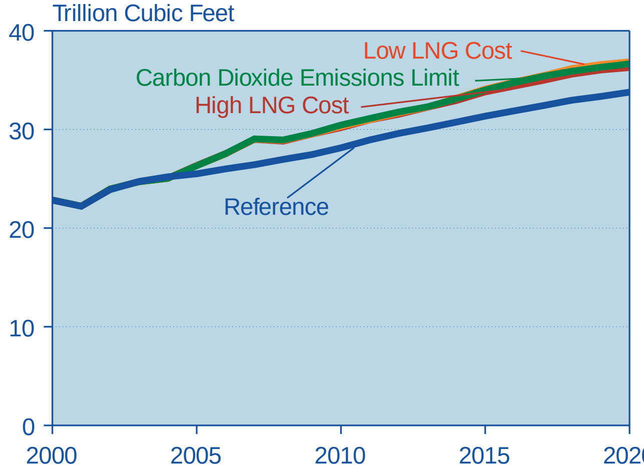
Key Results for Natural Gas	2000	Projections: Reference Case	Projections: Carbon Dioxide Emissions Limit Case	Analysis Cases: High LNG Cost[a]	Analysis Cases: Low LNG Cost[a]
		2010			
Net LNG Imports (Trillion Cubic Feet)	0.16	0.83	0.87	0.83	1.02
Total Natural Gas Production (Trillion Cubic Feet)	18.99	23.48	24.79	24.61	24.52
Lower 48 Average Wellhead Price (2000 Dollars per Thousand Cubic Feet)	3.60	2.85	3.81	3.86	3.81
Total Natural Gas Consumption (Trillion Cubic Feet)	22.55	28.13	30.44	30.18	30.31
		2015			
Net LNG Imports (Trillion Cubic Feet)	0.16	0.83	1.26	0.83	1.58
Total Natural Gas Production (Trillion Cubic Feet)	18.99	26.32	27.83	28.05	27.55
Lower 48 Average Wellhead Price (2000 Dollars per Thousand Cubic Feet)	3.60	3.07	3.37	3.50	3.33
Total Natural Gas Consumption (Trillion Cubic Feet)	22.55	31.34	34.00	33.80	34.09
		2020			
Net LNG Imports (Trillion Cubic Feet)	0.16	0.83	1.35	0.83	1.74
Total Natural Gas Production (Trillion Cubic Feet)	18.99	28.48	30.16	30.20	29.99
Lower 48 Average Wellhead Price (2000 Dollars per Thousand Cubic Feet)	3.60	3.26	3.72	3.79	3.63
Total Natural Gas Consumption (Trillion Cubic Feet)	22.55	33.78	36.65	36.27	36.85

[a]The high and low LNG cost cases include the carbon dioxide emissions limit.

Note: The values shown for 2000 represent the most current natural gas data available when this report was published. The values shown for 2000 in Appendixes B and C represent the most current natural gas data available when the model runs were produced.

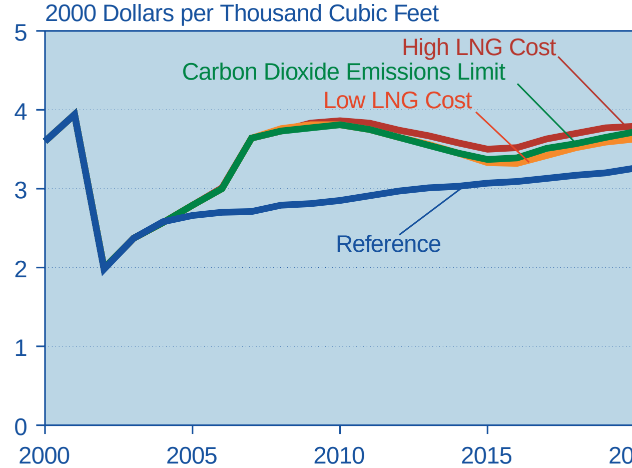
Sources: **2000 Net LNG Imports , Lower 48 Production, and U.S. Consumption:** Energy Information Administration, *Natural Gas Annual 2000*, DOE/EIA-0131(00) (Washington, DC, November 2001). **2000 Lower 48 Wellhead Price:** Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, HCSTHDEM.D111201A, and LCSTHDEM.D111201B.

Figure 14. Projected Natural Gas Consumption in Four Cases, 2000-2020



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, HCSTHDEM.D111201A, and LCSTHDEM.D111201B.

Figure 15. Projected Lower 48 Wellhead Natural Gas Prices in Four Cases, 2000-2020

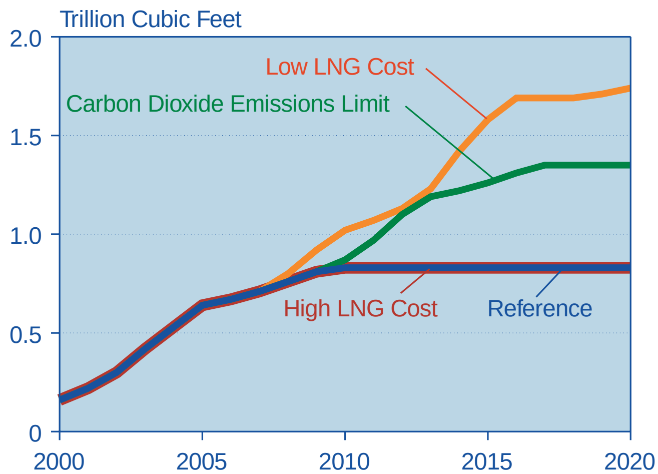


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, HCSTHDEM.D111201A, and LCSTHDEM.D111201B.

the demand for natural gas continuing to increase, prices change direction and increase to $3.72 per thousand cubic feet in 2020. The total increase in sustainable LNG receiving terminal capacity by 2020 includes an increase in capacity over existing and proposed capacity at the four U.S. terminals of 526 billion cubic feet.

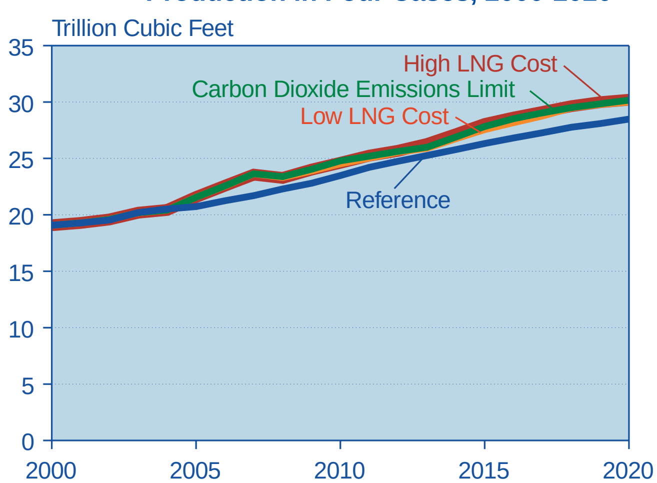
In the low LNG cost case, lower LNG costs trigger expansion at existing U.S. LNG receiving facilities and construction of new facilities. LNG is projected to meet 4.7 percent of total U.S. natural gas demand by 2020 (as compared with 0.7 percent in 2000 and 2.3 percent in 2020 in the high LNG cost case). The projected level of expansion in the low LNG cost case exceeds that in the carbon dioxide emissions limit case by 912 billion cubic feet. Total LNG imports in 2020 are projected to increase to 1.8 trillion cubic feet in the low LNG cost case, double the 0.9 trillion cubic feet projected in both the carbon dioxide emissions limit case and the reference case. The level of LNG imports grows steadily each year, leveling off in 2016 and then increasing again beginning in 2019. Average wellhead prices in the low LNG cost case reach a high of $3.81 per thousand cubic feet in 2009 and 2010, which leads to expansion and new construction of LNG receiving facilities in both the South Atlantic and West South Central regions. The projected increase in LNG imports has an immediate effect on prices, which fall to $3.32 per thousand cubic feet by 2016 in the low LNG cost case. Prices then begin increasing, reaching $3.59 per thousand cubic feet in 2019, when LNG capacity again begins to increase.

Figure 16. Projected Net LNG Imports in Four Cases, 2000-2020



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, HCSTHDEM. D111201A, and LCSTHDEM.D111201B.

Figure 17. Projected Lower 48 Natural Gas Production in Four Cases, 2000-2020

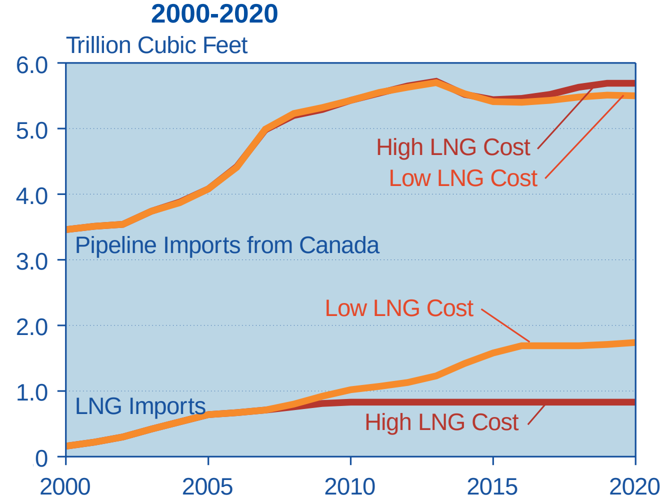


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, HCSTHDEM. D111201A, and LCSTHDEM.D111201B.

Conclusion

The results of EIA's analysis suggest that increased imports of LNG could have a positive effect on U.S. natural gas markets, especially in an environment of high demand. LNG can meet demand that otherwise would have to be met by higher cost sources, thus tempering price increases. If only a fraction of the LNG terminal capacity currently proposed is built, LNG could capture a much larger portion of the U.S. import market for natural gas than it holds today. In some regions, LNG could have a proportionately larger impact.

Figure 18. Projected Net Imports of LNG and Canadian Natural Gas in Four Cases, 2000-2020



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs AEO2002.D102001B, CAPE2002.D111101A, HCSTHDEM. D111201A, and LCSTHDEM.D111201B.

4. Mid-Term Trends in Natural Gas Supply and Prices: Potential for Cyclic Price and Investment Behavior

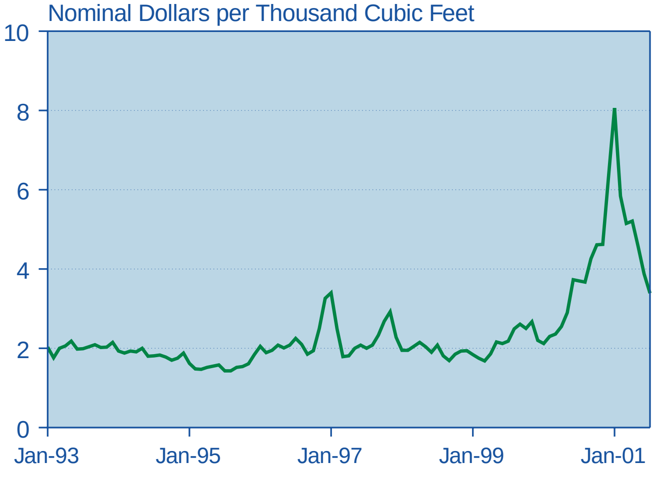
Introduction

This chapter explores the issue of whether the domestic natural gas market can be expected to exhibit a new behavior pattern with respect to long-term wellhead natural gas supply, and the potential market implications of such behavior. In particular, did the recent rise and fall of natural gas prices signal a fundamental change in the long-term pattern of investment, drilling, wellhead supply, and prices in U.S. natural gas markets?

Commodity prices can exhibit four distinct patterns over time:

- A commodity's price behavior can exhibit a long-term trend. For example, from 1993 through 1999 (Figure 19), monthly wellhead natural gas prices were relatively constant, averaging \$2.00 per thousand cubic feet (in nominal dollars) with a standard deviation of \$0.36 per thousand cubic feet. Although wellhead prices varied over the period, \$2.00 per thousand cubic feet can be viewed as the long-term price trend.
- A commodity's price can exhibit a seasonal pattern. Natural gas has demonstrated over the years a seasonal pricing pattern, with winter prices typically higher than summer prices due to greater winter consumption levels.

Figure 19. Average Monthly Wellhead Natural Gas Prices, January 1993 - July 2001



Source: Monthly natural gas price data series (N9190US3) from Energy Information Administration, web site http://tonto.eia.doe.gov/oog/ftparea/wogirs/xls/ngm04vmwhprc.xls.

- A commodity's price can reflect the influence of random events, such as oil embargos, pipeline ruptures, hurricanes, and abnormally cold or hot temperatures. Natural gas prices certainly have been influenced by such random events. For example, during a 2-week period in February 1996, Henry Hub spot prices went above \$5.00 per thousand cubic feet because of unseasonably cold temperatures. The severe weather was short-lived, and spot prices quickly declined when temperatures rose.
- A commodity's price can exhibit a periodic cycle of high and low prices over several years, reflecting a business investment cycle. To date, the natural gas supply industry has not conclusively demonstrated such cyclic price behavior. However, the run-up in wellhead prices during 2000 and their subsequent decline during 2001 raises a question as to whether the natural gas supply industry might be entering a new era of cyclic price fluctuations typical of a commodity business cycle.

Industry Restructuring and Market Price Behavior

Over the past 15 years there has been a significant transformation both in natural gas supply and natural gas consumption. Wellhead price deregulation has permitted natural gas prices to adjust freely to prevailing supply and demand conditions, and open-access transportation has allowed natural gas volumes to move freely from producers to consumers. As a result of industry restructuring, natural gas supply, demand, and prices are now subject to competitive market forces, which are largely responsible for recent efficiency gains in natural gas production.

Natural gas industry restructuring has heightened supply competition and caused natural gas suppliers to minimize per-unit fixed and operating costs by fully utilizing productive assets, in addition to using new technologies and management techniques to improve finding rates and decrease drilling and operating costs (see box on page 40). In 1985, natural gas productive capacity was operating well below full utilization (Figure 20). Between 1985 and 1993, seasonal consumption variations were partly met by variable wellhead production. By 1993, capacity had come close to full effective utilization. (Full effective utilization appears to be in the range of 93 to 95 percent of total productive capacity. The seasonal variation in capacity utilization reflects seasonal variation in natural gas consumption.) Since 1993, capacity utilization has continued to increase slightly. Probably the highest possible operationally feasible utilization level was achieved in late 2000. Near full capacity utilization, wellhead natural gas production is

Recent Efficiency Improvements in the Natural Gas Production Industry

Efficiency improvements in the natural gas production industry since the introduction of wellhead price deregulation and open-access transportation can be gauged by examining a number of secondary measures. Indirect measures must be used, because per-unit production costs cannot be measured directly for a number of reasons, including:

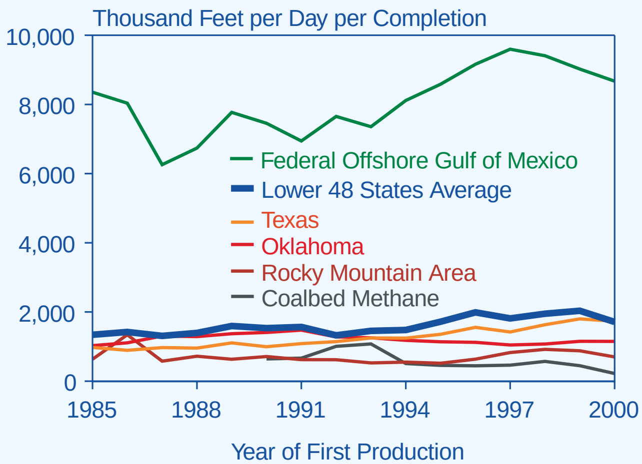
- Co-production of natural gas, natural gas liquids, and oil from the same wells
- Reporting of natural gas reserves additions and natural gas well drilling activities at different points in time
- Inability to apportion "dry well" drilling costs precisely to oil and natural gas production
- Reporting of wells that produce both oil and natural gas as "oil wells"
- Lack of reporting on lease payments and geophysical expenses or, when they are reported, inability to apportion them to oil and natural gas.

Two secondary measures of natural gas production industry efficiency can be evaluated from 1985 through the present, a period when the industry has operated in a fully competitive market environment.

The initial flow rate of new natural gas well completions is an indicator of how well natural gas producers are doing in replacing depleted wells. As shown in the following figure, lower 48 gas wells have demonstrated higher initial rates of production, going from 1,341 thousand cubic feet per day per completion in 1985 to 1,712 thousand cubic feet per day per completion in 2000. Because initial production rates vary from year to year, a comparison of 5-year averages best illustrates the trend. From 1986 through 1990, the initial gas well completion averaged 1,451 thousand cubic feet per day per completion; from 1996 through 2000, the average initial completion rate was 1,900 thousand cubic feet per day per completion, an increase of 31 percent. Much of the improvement can be attributed to Texas, where the average initial flow rate increased from 975 thousand cubic feet per day per completion in 1985 to 1,732 thousand cubic feet per day per completion in 2000, a 78-percent increase. In comparison, the increases in other regions were less impressive: 3.8 percent for the Gulf of Mexico, 11.9 percent for Oklahoma, and 10.4 percent for the Rocky Mountain region.

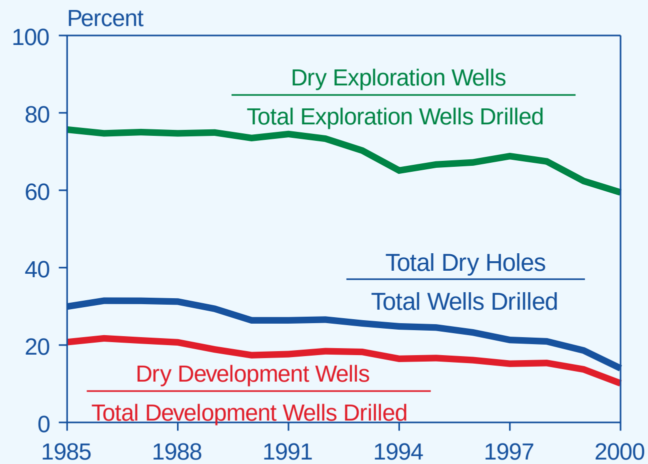
Perhaps one of the least ambiguous measures of increased drilling efficiency is the percentage of dry holes drilled by the oil and natural gas industry in the pursuit of new oil and natural gas reserves. (Because dry holes cannot be strictly attributed to either the oil or natural gas side of the industry, the percentage of dry holes drilled in the search for natural gas cannot be determined.) Irrespective of the type of well drilled, dry holes have declined as a percentage of the total oil and natural gas wells drilled, as shown in the figure below.

Initial Flow Rates of New Natural Gas Well Completions, 1985-2000



Source: Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

Dry Holes as a Percentage of Oil and Natural Gas Wells Drilled, 1985-2000



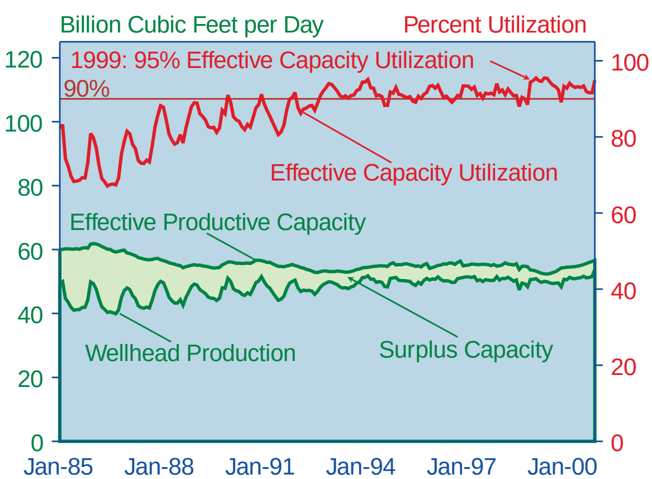
Source: Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

less responsive to short-term consumption variations. As a result, wellhead natural gas production has become less elastic with respect to price and consumption in the short-term, as demonstrated by the decline in the monthly production variation since 1985 (Figure 21).

Competitive natural gas production markets have kept wellhead prices sufficiently low to encourage significant growth in natural gas consumption. Since 1983, when natural gas consumption bottomed out, it has increased by 35 percent, from 16.8 trillion cubic feet in 1983 to 22.7 trillion cubic feet in 2000.[85] Of the major natural gas consumption sectors, electricity generation has posted the largest growth, from 274 billion kilowatthours of electricity produced from natural gas in 1983 to 596 billion kilowatthours in 2000.[86] Natural gas was responsible for 16 percent of total electricity generation in 2000, compared with 12 percent in 1983. Commensurately, electricity production consumed 28 percent of total natural gas supply in 2000, compared with 17 percent in 1983.[87] Continuing growth in natural-gas-fired electricity generation could have profound implications for future natural gas markets.

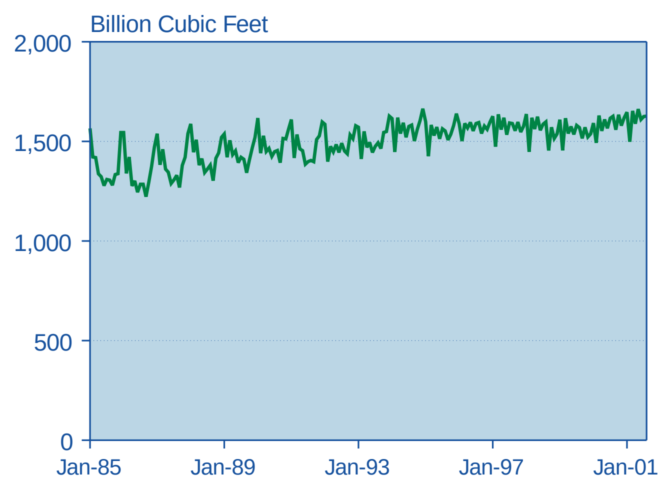
The four largest energy sources for electricity generation are coal, nuclear, hydropower, and natural gas. Because natural-gas-fired generators have the highest fuel and operating costs, they typically are dispatched last to the transmission grid and provide mostly peaking load power and some intermediate load power.[88] Peak and intermediate electricity requirements are determined largely by variations in demand for summer cooling and winter heating. Because of the growth in natural-gas-fired electricity generation capacity, natural gas consumption has become more sensitive to weather variations.[89]

Figure 20. Lower 48 Monthly Natural Gas Production, Effective Productive Capacity, and Effective Capacity Utilization Rate, 1985-2001



Source: Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

Figure 21. Lower 48 Natural Gas Production, January 1985 - August 2001



Source: Monthly natural gas price data series (N9070US1) from Energy Information Administration, web site http://tonto.eia.doe.gov/oog/ftparea/wogirs/xls/ngm01vmall.xls.

[85] Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001), Table 6.1, p. 177.

[86] Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001), Table 8.2, p. 221. Total net electricity generation equaled 2,310 billion kilowatthours in 1983 and an estimated 3,792 billion kilowatthours in 2000.

[87] Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001), Table 6.5, p. 185. Total natural gas consumption for electricity generation equaled 2.9 trillion cubic feet in 1983 and an estimated 6.3 trillion cubic feet in 2000. The 2000 figure includes both independent power production and cogeneration.

[88] This is a simplification, because the mix of generation assets (i.e., hydroelectric, nuclear, coal and natural gas) varies greatly from region to region. Consequently, some areas of the country could be using natural-gas-fired capacity for baseload generation while other areas use it exclusively for peak load demand. Because more than 50 percent of all oil- and natural-gas-fired capacity is dual-fired, a capacity factor cannot be determined separately for natural-gas-based capacity. A combined capacity factor for oil- and natural-gas-fired capacity can be calculated from 1989 through 2000, during which fuel-specific electricity generation capacity data were collected by the Energy Information Administration. The average combined capacity factor was 27.7 percent in 1989 and 28.6 percent in 2000, indicating that on a national basis the capacity serves primarily intermediate and peak power loads, and that the situation did not change appreciably from 1989 through 2000.

[89] The validity of this observation is not dependent on whether natural gas heating requirements and natural gas electricity generation requirements are coincident events or separate seasonal events. Although generation requirements peak during the summer cooling season, they also have a significant peak in the winter heating season, which is coincident with the natural gas space heating peak. Even so, extremely high levels of summer natural-gas-fired electricity generation could reduce winter natural gas supplies by diverting wellhead natural gas supplies away from summer storage injection. This would reduce the following winter's working gas in storage and its ability to moderate winter price increases.

Natural Gas Industry Attributes That Could Facilitate Future Investment and Price Cycles

The natural gas production industry possesses the causal attributes necessary for business cycle behavior:

- Relatively inelastic supply and demand in the short term, which can cause large fluctuations in price during periods of relative scarcity or abundance of supply
- Large fluctuations in producer cash flows and investments, leading to large fluctuations in wellhead gas supplies, as a result of large price fluctuations
- Significant delays (approximately 6 to 18 months) between changes in price and changes in wellhead gas supply, which encourage overinvestment when prices are high and underinvestment when prices are low, relative to gas demand
- Rapid declines in production from new natural gas wells, which could rapidly turn a supply surplus into a deficit during a period of low producer investment.

Short-Term Inelasticity of Natural Gas Supply and Demand

From early 2000 through mid-2001, a scarcity of available natural gas supplies led to sustained high wellhead prices for natural gas for the first time since the early 1980s. This event was unique for a number of reasons. First, it occurred in a fully competitive market environment in which natural gas producers were operating their productive assets at full utilization. In contrast, the high wellhead natural gas prices of the early 1980s were caused by market distortions imposed by the regulation of wellhead natural gas prices, when producers were operating at well below full capacity utilization. Second, the volume of weather-sensitive natural gas consumption has grown substantially, primarily due to the growth in natural-gas-fired electricity generation capacity. High wellhead utilization in conjunction with a colder winter caused high and sustained natural gas prices. In addition to other factors, such as a low level of Northwest hydroelectric capacity, the sustained high natural gas prices reflect the relative inflexibility of short-term natural gas production, because natural gas drilling—and ultimately natural gas production—could not immediately respond to the higher prices.

Like wellhead natural gas supplies, other sources of natural gas supply were also relatively inelastic. For example, while the volume of weather-sensitive natural gas consumption has grown, the capability of natural gas storage facilities to reduce high prices during periods of high winter demand appears to have diminished. In 1988, total working gas storage capacity equaled 4,324 billion cubic feet. By 2000, total working gas storage capacity had declined to 3,962 billion cubic feet.[90] The decline was offset to some extent by growth in capacity at salt cavern storage fields, which are more suited to supplying large volumes of natural gas over short periods of time. In 2000, salt cavern storage working gas capacity totaled 75 billion cubic feet.[91] Moreover, the maximum withdrawal rates of some reservoir storage fields have been increased over the past decade through additional wells for withdrawing natural gas. Nevertheless, the volume of weather-sensitive natural gas demand has grown significantly while the capability of natural gas storage facilities has, at best, remained constant. As a result, natural gas supply from storage facilities would be expected to have become a less elastic natural gas supply source relative to the magnitude of potential swings in natural gas consumption.[92]

[90]Base gas is gas held in permanent inventory to maintain adequate underground storage reservoir pressures and withdrawal rates; working gas is gas held for withdrawal as needed. 1988 was the first year that total natural gas storage capacity was reported. Total storage capacity is the sum of base and working gas capacity volumes. The 1988 working gas capacity volume equals the total capacity figure of 8,124 billion cubic feet minus a reported base gas volume of 3,800 billion cubic feet. The 2000 working gas capacity volume equals the total capacity figure of 8,241 billion cubic feet minus a reported base gas storage volume of 4,279 billion cubic feet. Source for total storage volume: Energy Information Administration (EIA), *Natural Gas Annual 1988*, Table 13, and *Natural Gas Annual 2000*, Table 14. Source for base gas storage volumes: EIA, *Annual Energy Review 2000*, Table 6.7. It should be noted that the definition of "base gas" storage volumes has some flexibility. For example, it has been reported that some storage operators withdrew base gas during the 2000-2001 winter to serve consumers. Moreover, natural gas storage facility maximum withdrawal rates are as important as the actual volume of working gas capacity, but they are not collected by EIA. Consequently, the actual capability of natural gas storage to moderate extreme price swings is neither precisely defined nor measured, although it is generally acknowledged that higher working gas storage volumes can better moderate winter natural gas price increases than can lower volumes.

[91]Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001), Table 6.7.

[92]Natural gas storage use moderates summer price declines and winter price increases, but it does not change the overall natural gas supply situation, because gas withdrawals normally equal gas injections over the course of a year. Gas storage contracts usually require contract parties to withdraw all the natural gas injected by the end of the winter heating season (March 31) to make the capacity available to next season's users. Consequently, natural gas storage facilities change the timing of when natural gas supplies are made available to consumers, but they do not change whether natural gas supplies are fundamentally scarce or abundant, relative to demand.

Another natural gas industry attribute that contributes to the inelasticity of natural gas supplies is the fact that the U.S. natural gas market, although tightly integrated with the Canadian natural gas market, is relatively isolated from overseas natural gas supplies. In contrast, the well integrated international oil trade moves crude oil and petroleum products to or from the United States when there are relatively small price differentials between the U.S. and the overseas markets. These trade movements are feasible because the cost of bulk shipping is inexpensive and because there is considerable spare tanker capacity on the world market. Consequently, any relative scarcity or abundance of petroleum in the U.S. market can be moderated by shipments of petroleum to or from overseas markets. Given the limited U.S. infrastructure for imports of liquefied natural gas (LNG) and the limited extent of international LNG trade, the isolation of the U.S. and Canadian natural gas markets from overseas markets limits the degree to which spot LNG shipments can moderate price extremes.

In 1999, LNG imports accounted for 163 billion cubic feet or 0.7 percent of total U.S. and Canadian natural gas consumption.[93] Although 2000 LNG imports increased to 226 billion cubic feet, this still amounted to less than 1 percent of total U.S. and Canadian natural gas consumption. Two U.S. LNG terminals are expected to be reactivated soon, increasing sustainable U.S. import capacity to 718 billion cubic feet per year, or 3 percent of total U.S. and Canadian natural gas consumption, it is unclear whether the facilities will be delivering any LNG on a spot cargo basis.

If spot LNG cargos were feasible, then LNG could be a swing source of natural gas supplies by providing additional supplies during periods of high natural gas prices and by curtailing LNG shipments during periods of low natural gas prices. The feasibility of spot LNG deliveries depends on such issues as the availability of LNG tankers, whether current contract commitments at U.S. LNG terminals would preclude spot LNG deliveries, and the availability of spare overseas liquefaction capacity to load spot cargos. Currently, LNG is not a large enough portion of the total U.S. and Canadian market to alleviate extreme price fluctuations.

Natural gas consumption is also relatively inelastic to prices in the short term, because natural gas consumption equipment typically has lifetimes in excess of 15 years. The short-term inelasticity of natural gas demand increases the probability that natural gas supplies could be either comparatively abundant or scarce relative to prevailing natural gas consumption requirements. This natural gas market attribute of relative supply abundance or scarcity can lead to wide swings in natural gas prices, setting the stage for the possibility of surfeits or deficits of investment in new natural gas well productive capacity relative to potential natural gas consumption.

Price adjustments ultimately succeed in balancing supply and demand in the U.S. natural gas market, because neither demand nor supply is completely rigid or fixed in the short term. For example, natural gas producers can place skid-mounted compressors in the field to withdraw natural gas more rapidly from the reservoir. Or they can decide not to remove the natural gas liquids (ethane, propane, butane) from gross wellhead volumes, so that they can deliver larger natural gas volumes when the value of the natural gas exceeds the value of the entrained liquids. On the demand side, some industrial and electricity generation consumers can switch dual-fired equipment from natural gas to oil. Other industrial consumers can sell the higher value natural gas rather than use it as a feedstock to produce a lower value product (e.g., ammonium hydrate). The responsiveness of supply and demand ultimately depends on the cost or value of implementing a specific supply or consumption response, relative to the prevailing natural gas price, and the time delay associated with implementing that response. The extremely high and sustained natural gas prices of late 2000 and early 2001 indicate, however, that the costs could be higher and the delays longer than might have been thought to be the case.

Dependence of New Productive Capacity on Producer Cash Flows and Prices

Exploration and development activities for new natural gas wells are dependent on production cash flow for new investment capital. Cash flow equals revenues

[93] 1999 Canadian natural gas consumption equaled 64,921 million cubic meters or 2.29 trillion cubic feet. Source: “1999 Statistical Handbook for Canada’s Upstream Petroleum Industry,” Canadian Association of Petroleum Producers. 1999 U.S. natural gas consumption was 21.62 trillion cubic feet; Energy Information Administration, *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001), Table 1.

(price times production volumes) minus costs. Recent history has demonstrated that when prices are high, cash flows are also high, inducing investment and drilling (Figure 22).[94] Natural gas drilling activity, in turn, is directly related to the development of new productive capacity. A comparison of new natural gas discoveries and annual natural gas drilling rig levels shows that new natural gas discoveries are correlated with drilling rig rates (Figure 23).[95] Higher gas rig levels generally result in a higher level of natural gas discoveries. For example, during 2000, the high average gas rig count of 720 resulted in 19,138 billion cubic feet of new natural gas discoveries.

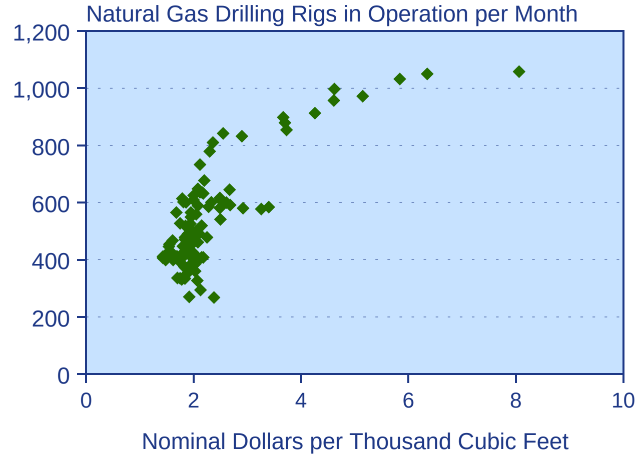
Given these relationships, high natural gas prices will result in high levels of new natural gas productive capacity, and low natural gas prices will result in low levels of new natural gas productive capacity. The industry potential for extreme price swings raises the question as to whether the level of new natural gas productive capacity will tend to overshoot or undershoot the level of supply necessary to match natural gas demand requirements. The inherent time delays between price level changes and wellhead supply changes suggest that this will be the case.

Delays Between Price Changes and Drilling Investments

New wellhead natural gas supplies will increase or decrease as wellhead prices increase or decrease, but the response is not immediate. Depending upon circumstances (e.g., onshore versus offshore production), the delay may range between 6 and 18 months. Because natural gas producers want some assurance that wellhead prices will be high enough for long enough to justify new investment, there is some tendency for producers to defer higher drilling investment levels until they are convinced that the higher prices do not represent a short-lived price spike.

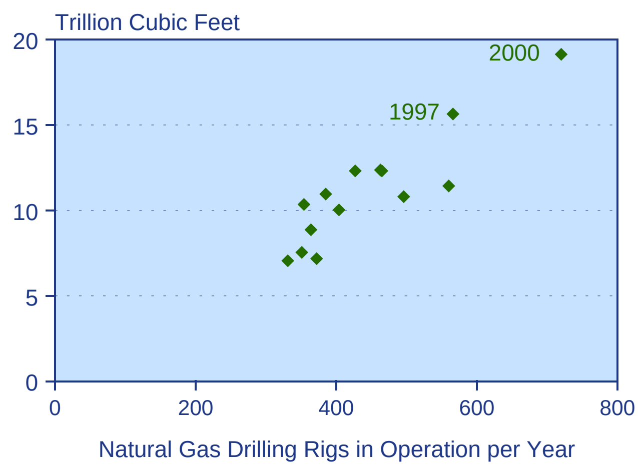
In addition, there is a delay between the time when natural gas producers decide to increase their drilling budgets and when the new wells are completed. This delay encompasses contracting for the drilling, transporting and assembling drilling rigs on leases, drilling the wells,

Figure 22. Scatter Plot of Monthly Natural Gas Drilling Rigs Versus Wellhead Natural Gas Prices 6 Months Earlier, July 1992 - September 2001



Sources: See footnote 94.

Figure 23. New Natural Gas Discoveries as a Function of Average Annual Natural Gas Drilling Rigs, 1987-2000



Sources: See footnote 95.

94Figure 22 shows the relationship between monthly wellhead natural gas prices and the average monthly number of rigs drilling for natural gas. Drilling rig data were obtained from the Baker-Hughes web site, bakerhughes.com/investor/rig/index.htm, from which the database "US Rig Report.xls" was downloaded. The average monthly natural gas rig count equals the arithmetic average of the weekly data. In Figure 22, the average wellhead natural gas price is "led" 6 months relative to the gas rig numbers. That is, September 2001 gas rig rates are matched with March 2001 natural gas prices. Thus, the natural gas price data series encompassed the period of July 1992 through March 2001, and the gas drilling rig data series encompassed the period January 1993 through September 2001. January 1993 was chosen as the starting point for the gas drilling rig data, because 1993 appears to be the first full year in which natural gas productive capacity exceeded 90 percent, which would make drilling more responsive to prices than in the earlier period when considerable spare productive capacity existed. The correlation coefficient for the two data series is 0.804, which indicates that 80 percent of the variation in gas drilling rig levels can be explained by the variation in wellhead natural gas prices. Monthly natural gas price data series (N9190US3) from Energy Information Administration, web site http://tonto.eia.doe.gov/oog/ftparea/wogirs/xls/ngm04vmwhprc.xls.

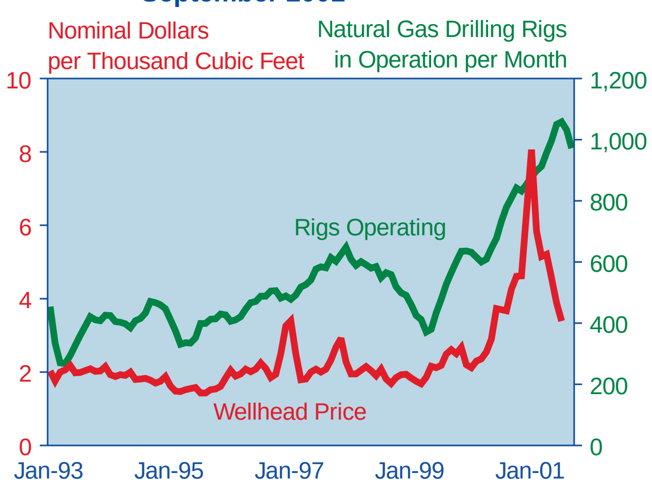
95The correlation coefficient for the two data series in Figure 23 is 0.898. However, the relatively low number of data points limits the ability to make an inference from this statistic. Natural gas discoveries equal new field discoveries, plus new reservoir discoveries in old fields, plus extensions. See Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216 (Washington, DC, 1993 through 2000 annual reports), for detailed definitions of reserve categories. Annual average natural gas drilling rig count is the arithmetic average of the weekly gas rig counts. See footnote 94 for gas drilling rig data source.

cementing the wells, fracturing the formations, and attaching the wells to gathering systems. If drilling rigs are in short supply, there will be an additional wait until a rig becomes available or a new rig is manufactured.

Wellhead prices will remain at high levels until sufficient new productive capacity is brought into operation, relative to demand, to cause wellhead prices to decline. Then, there will be another delay between the onset of the decline in prices and a reduction in drilling activity by producers. For example, average wellhead prices peaked in January 2001 at $8.06 per thousand cubic feet and fell to $3.39 per thousand cubic feet by July 2001, but the gas rig count did not peak until July 13, 2001, at 1,068 gas rigs, and had only declined to 876 rigs by October 26, 2001 (Figure 24). A key impediment to rapid reduction of drilling activity is that drilling contracts typically specify a minimum level of drilling activity by the service company over the life of a contract.

The recent natural gas price and drilling rig situation suggests that the time delay between natural gas price changes and wellhead natural gas supply changes could cause such an abundance of wellhead productive capacity that natural gas prices will become quite low in 2002. In 2001, the average annual gas rig count through October 26, 2001, was 969 rigs. If the rig count were to drop by 33 to 50 gas rigs per week for the remaining 9 weeks of 2001, then the year-end gas rig count would be 579 to 426, and the average annual rig count would be 924 to 910. At an annual average count of 910 to 924 rigs, 2001 natural gas discoveries could be in the range of 22 to 24 trillion cubic feet.[96] Yet, the average annual rate of new natural gas discoveries from 1995 through 1999 equaled 12.2 trillion cubic feet per year.[97] With new wellhead natural gas discoveries in 2000 replacing 99.6 percent of that year's natural gas production,[98] and with the prospect for even higher reserve discoveries in 2001, the large additions to wellhead natural gas supply during 2000 and 2001 create the potential for a significant decline ("bust") in wellhead natural gas prices. Whether or not a wellhead price bust will materialize should become apparent by the spring of 2002, at the conclusion of the winter heating season.

Figure 24. Average Monthly Natural Gas Wellhead Prices and Drilling Rigs, January 1993 - September 2001



Source: See footnote 94 on page 44.

The delay between changes in price and changes in new wellhead supplies increases the propensity of natural gas producers to overinvest in new productive capacity during periods of high wellhead prices. During the "boom" phase of a business cycle, producers will continue to invest at high levels as long as wellhead prices remain high, even though there could be sufficient investment already underway to ensure adequate natural gas supplies. When wellhead prices begin to fall, the delay in cutting back drilling activity ensures that additional supplies will come into the market even after their economic justification has apparently disappeared. The resulting overabundance of wellhead natural gas supplies will then induce a precipitous drop in prices.

If natural gas prices fall below the long-run marginal price necessary to maintain adequate wellhead natural gas supplies, producers will be induced to underinvest in new wellhead natural gas capacity; and given the inherent time delays in the price and investment cycle, the underinvestment in new natural gas productive capacity will continue well after natural gas prices begin to rise, signaling the disappearance of surplus natural gas productive capacity. A period of extended underinvestment could rapidly turn an abundance of wellhead natural gas capacity into scarcity of supply.

More Rapid Declines in the Production Rate From New Natural Gas Wells

In recent years, production from new natural gas wells has been declining more rapidly than in the past. This

[96]A linear regression, where gas discoveries = coefficient times average annual gas rigs, yields the following results: coefficient = 25.045, standard error = 0.8557, t-statistic = 29.27, R-squared = 0.8011, Durbin-Watson statistic = 1.813.

[97]For 1995 through 1999, average annual total natural gas reserve additions (i.e., natural gas discoveries plus net revisions and adjustments) equaled 19,451 billion cubic feet. In 2000, total natural gas reserve additions equaled 25,209 billion cubic feet, excluding net of sales and acquisitions. See Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216 (Washington, DC, 1993 through 2000 annual reports).

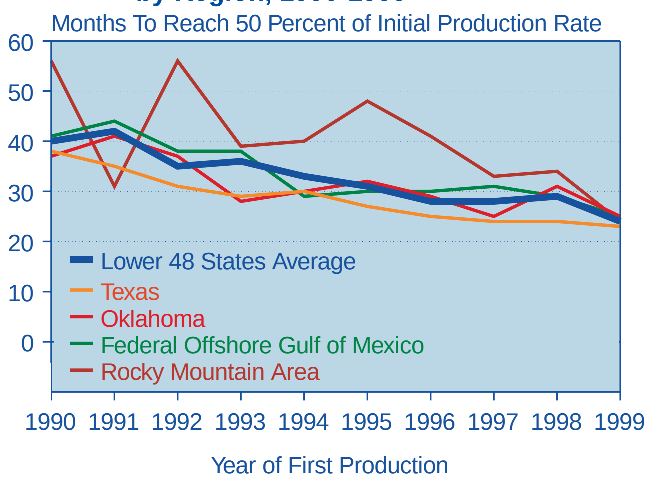
[98]Total natural gas reserve replacement for 2000 was 131 percent when new natural gas discoveries plus net revisions and adjustments are considered and net sales and acquisitions are excluded. Only new wellhead natural gas discoveries are considered in this discussion, because new reserves are a direct result of the natural gas found through drilling activity. In contrast, reserve revisions can represent the installation of recovery equipment that is made more affordable by high natural gas prices.

phenomenon is best illustrated through the concept of a production half-life. The production half-life represents the amount of time that passes before a well (or a group of wells) produces natural gas at 50 percent of its (their) initial production level. This figure can be calculated for all wells that began producing in a given year (e.g., vintage 1990 wells), allowing a comparison across years (Figure 25). Natural gas well production rates were declining much faster at the end of the 1990s than they were at the beginning of the decade. Although there is some year-to-year variation in the trend, the 1990 and 1999 data illustrate the dramatic change in gas well half-lives[99] (Table 12).

Two trends are apparent from the data in Table 12. First, the average gas well half-life has dropped for all major production regions and for the lower 48 States. Second, the regional gas well production half-lives have converged to a value of between 23 and 25 months. Although individual well performance varies, the 1999 regional production half-lives show surprising uniformity.

A number of factors can influence a natural gas well's production half-life, including the innate characteristics of the reservoir, the introduction of higher production rate technology (e.g., horizontal drilling and completions), low wellhead natural gas prices (which can cause producers to reduce production below a well's full capability), lack of sufficient pipeline capacity, and State conservation regulations. Indeed, the fact that natural gas wells were not operating at full productive capacity before 1993 suggests that well production half-lives would be lower today than they were before 1993. Regardless of the cause, a more rapid decline in wellhead productive capacity requires producers to drill more wells per year in order to maintain a given level of natural gas production.

Figure 25. Natural Gas Well Production Half-Lives by Region, 1990-1999



Source: Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

More rapid declines in natural gas well production have been actively pursued by producers through the application of technology, in order to improve their financial position. Increasing near-term cash flow is of paramount importance to the oil and gas business. Production rate technologies that enhance near-term cash flows increase the net present value of the discounted cash flow, improve rates of return, reduce the investment payback period, and lower producers' exposure to future price risk. But better production rate technology is a double-edged sword. While it improves the near-term financial position of producers, it simultaneously increases the requirement for natural gas well investment in the next year and the year beyond.

If natural gas well drilling were to stop completely, productive capacity in the lower 48 States would decline by between 14 and 22 percent after 1 year and between 26 and 39 percent after 2 years.[100] Thus, next year's stock of productive capacity depends on the extent of this year's drilling. At the same time, natural gas well drilling activity depends on producer cash flow, which in turn depends on wellhead price levels. Consequently, low wellhead natural gas prices over any sustained period of time will lower producer cash flow, and could cause natural gas drilling to decline sufficiently to cause productive capacity to be less than the potential natural gas demand within a period as short as one year. In the bust phase of a business cycle, low prices, low cash flows and low investment levels will increase the probability that natural gas supplies will fall quickly and cause a deficit in wellhead productive capacity relative to natural gas demand.

Because neither productive capacity nor consumption is highly elastic with respect to price in the short term, a relative scarcity of wellhead productive capacity could

Table 12. Natural Gas Well Production Half-Lives by Region, 1990 and 1999
(Number of Months in Production Before Reaching 50 Percent of Initial Production Rate)

Region	1990	1999
Texas	38	23
Oklahoma	37	25
Rocky Mountain	56	24
Offshore Gulf of Mexico	41	25
Lower 48 States	40	24

Source: Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

[99] 1999 is the last data point presented because sufficient experience with a well's production profile is necessary before its half-life can be calculated.

[100] Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

be expected to cause very high natural gas prices, and a relative surplus could be expected to cause very low prices. When supply is relatively scarce, the short-term inelasticity of consumption and the delay associated with new natural gas supply investment will tend to cause natural gas prices to overshoot the long-run market-clearing wellhead price. This price behavior, in conjunction with the investment delays, would contribute to the tendency for natural gas productive capacity to overshoot demand, followed by an extended period of low prices and insufficient investment. Consequently, the natural gas industry embodies a set of dynamics that can cause periodic cycles in investment, drilling, supply, and prices.

Implications of Large, Unpredictable Price Fluctuations

Because the restructuring of the natural gas industry and its operation within a more competitive market structure are relatively recent, there is little experience from which to predict its future course of behavior. As discussed above, the market dynamics of the natural gas industry suggest that future cycles in natural gas prices and supply investments are possible. Of course, the market is also subject to unforeseen events. For example, oil price shocks, domestic economic cycles, and random weather events all tend to destabilize the balance of natural gas supply and demand. Consequently, a natural gas supply business cycle would probably not exhibit predictable, periodic fluctuations in price and supply investments. Rather, the future behavior of natural gas markets may be more analogous to a group of people kicking a ball suspended on a string. The suspended ball has a tendency to oscillate (around a long-run equilibrium), but the kicks change both the ball’s direction and the amplitude of its oscillations.

In the U.S. natural gas market, the extent of the price peaks and troughs during a market cycle will depend largely on weather conditions. Weather is a random force that can either reduce or exacerbate supply scarcity. When natural gas supplies are scarce, abnormally warm winters will moderate price increases; when supplies are abundant, warm winters will depress prices. Similarly, abnormally cold winter weather will exacerbate price increases when natural gas supply is already scarce and moderate price declines when supplies are abundant. Random weather effects, in conjunction with business cycle investment behavior, could result in thoroughly unpredictable prices and investment patterns. Such unpredictability could be further confounded by a whole range of events, such as oil price shocks and domestic economic cycles.

The unpredictability of future price behavior tends to obscure whether the natural gas industry is actually experiencing business cycle behavior and / or where it is situated with respect to any particular cycle. For example, wellhead productive capacity is not measured on any real-time basis. Wellhead natural gas prices are the only real-time measure of supply adequacy, but this measure is a relative one, which is also determined by prevailing consumption requirements. Although market analysts will associate causality to daily, weekly, and monthly wellhead price movements, the actual causes for price movements sometimes are not apparent until well after the fact, when more complete market data are available. Supply and demand uncertainty, in turn, encourages natural gas producers to delay reaction to market price changes, because of the risk of earning an inadequate rate of return on investment.

If large, unpredictable price excursions become common in the future, then the concept of a long-term price trend will be less meaningful to natural gas producers, consumers, and investors, because random short-term price excursions will confuse and obscure the longer term trends underlying the market at any point in time. Even if long-term price trends were clear, the risk associated with unpredictable price behavior could be financially devastating to natural gas producers, consumers, and investors in the short term.

The perceived financial viability of a natural gas supply investment depends, in part, on the price that the project sponsors expect to realize from the investment. Large, unpredictable price fluctuations expose potential projects to the possibility that when the project starts bringing its natural gas supplies to the marketplace, the price may be substantially lower than the price originally expected, imposing substantial risk on large capital-intensive projects that require long lead times, such as an LNG terminal or a natural gas pipeline from Alaska to the lower 48 States.

In contrast, short-lived supply projects that can be completed quickly during periods of high prices face less price risk. Projects that generally fit this description are conventional onshore drilling investments. Consequently, the potential for unpredictable future price behavior would result in an investment emphasis on near-term conventional drilling at the expense of investments in LNG terminals or an Alaskan pipeline, or in highly risky rank wildcatting, which is necessary to test new geophysical theories regarding natural gas formation and disposition. (Ironically, the future existence of extensive LNG infrastructure could potentially serve to moderate price fluctuations. LNG facilities could serve as “swing suppliers” of natural gas by providing incremental supplies during periods of high prices and curtailing shipments during periods of low prices.)

Unpredictable price fluctuations could also mask long-term trends in natural gas prices. For example, high prices during the natural gas shortages of the mid-1970s led many industry analysts to conclude that conventional natural gas supplies were insufficient to satisfy future natural gas consumption requirements. Many billions of dollars were invested in LNG terminals under the premise that inadequate domestic supplies would be reflected in high marginal production costs and high wellhead prices sufficient to justify LNG investments. Those expectations about long-term price behavior proved wrong, and the project sponsors lost substantial investment capital as a result.

Finally, unpredictable prices have deleterious consequences for natural gas consumers. For example, they obscure the value of appliances with higher energy efficiency ratings[101] and can affect the financial viability of large industrial projects, such as electricity generation plants and fertilizer plants, where natural gas supply is the largest component of operating costs. Consequently, new coal-fired projects might become more financially attractive than new natural-gas-fired projects, simply because coal prices would be expected to be more predictable and much less likely to exhibit extreme fluctuations.

The deleterious effects of cyclical prices on suppliers and consumers can be mitigated through long-term, fixed-price contracts and price hedging; however, those financial instruments are limited in their duration and access. It is unlikely, for example, that natural gas supply contracts would be written for terms longer than 5 years without price re-openers. Moreover, they are generally not available to small consumers, especially residential natural gas consumers, although many local natural gas distributors do have constant payment programs for residential consumers, which may mitigate the financial impacts of unpredictable prices.

[101] For example, periods of high natural gas prices might induce consumers to purchase higher efficiency appliances than they would have if their decision had been based on average natural gas prices.

5. The Need for Improved Data on Natural Gas

Introduction

In 2001, in an effort to understand recent natural gas market events and to evaluate possible policy options, industry and policy analysts turned to government and private-sector information sources. They found that they often wanted more frequent data measurements and greater geographic detail than were provided in existing data collection programs, and that both government and private-sector information programs had data gaps and problems. In many cases, available data could not be used to analyze desired policy options or accurately interpret current and future markets.

Natural gas market analysts use information from a variety of sources—including Federal and State agencies and private information sources—to assess historical trends, operate forecasting models, and examine market issues related to infrastructure operation, regulatory regimes, and business decisions. General understanding of natural gas market trends can be enhanced by access to more complete, accurate, and timely data as well as by additional or expanded analyses using improved analytical techniques. In the past few years, however, as the natural gas market has grown and changed, concerns about the adequacy of natural gas data for understanding markets have become significant.

The problems and limitations of existing data programs have affected the ability to conduct some forms of analysis of the changing, growing industry. In recognition of this situation, the Energy Information Administration (EIA) began its Next Generation*Natural Gas (NG2) initiative in 1998 to assess the effect of the restructuring of the industry and changing customer needs on its future natural gas information program. Analysts and industry observers generally became aware of the issue in the past year, when increased attention was focused on natural gas markets.

This chapter discusses current U.S. Federal Government information sources for data on production, foreign trade, storage activity, consumption, and pricing of natural gas, with emphasis on the data series available from EIA. It also discusses the extent to which the accuracy, timeliness, and detail of the various EIA data series are adequate to support analyses of important gas market issues and trends and outlines options that are being considered to change EIA's collection and dissemination of natural gas information.

Current Information Sources and Issues

A variety of EIA and other information sources currently contribute to understanding and tracking the operation of the natural gas industry. Data series provided by EIA describe portions of natural gas supply and reserves, disposition, and pricing for the United States and individual States. Other Federal agencies collect data to monitor natural gas resources, industry financial performance, or market structure and compliance with regulations for safety, environmental performance, and market operation. State agencies require data reporting for reasons such as royalty collection, resource conservation, monitoring of environmental and safety regulations, and tracking compliance with the requirements of State public utility commissions. Other information series, such as spot market prices and weekly reports of drilling rig activity, are provided by nongovernmental groups to members, subscribers, and the general public. Tables 13 and 14 summarize some of the principal sources of natural gas industry data.

Federal Government programs for the collection of economic data for the natural gas industry were originally designed for two purposes: to measure supply and consumption activity and to provide information for economic regulatory programs. The Bureau of Mines, U.S. Department of Interior, conducted voluntary annual surveys of the natural gas industry until 1977, when this function was transferred to EIA in the newly formed U.S. Department of Energy (DOE). The EIA natural gas data program also has roots in the data collection effort that EIA performed for many years on behalf of the Federal Energy Regulatory Commission (FERC), an independent commission with jurisdiction over the regulation of the interstate natural gas industry. The original collection programs reflected an industry of regulated producers, regulated pipelines, regulated local distribution companies (LDCs) delivering gas to end users, and regulated prices. Foreign trade was almost inconsequential, because net imports accounted for only about 4 percent of U.S. natural gas consumption in 1977.

The most important changes in the natural gas industry since the late 1970s have been deregulation of production prices and restructuring of major portions of the transmission system. In 1978 Congress passed the Natural Gas Policy Act, which began a phased decontrol of wellhead prices for different categories of natural gas. Price decontrol was completed with the passage of the Wellhead Decontrol Act in 1989. In a series of FERC orders in the 1980s and early 1990s, pipeline companies were required to provide nondiscriminatory access to transportation services. FERC Order 436 required interstate pipelines to provide nondiscriminatory access to transportation services. With the implementation of FERC Order 636, interstate natural gas pipelines became open access transporters, with no merchant function.

Similar changes in regulation have occurred at the State level since the mid-1990s. Increasing numbers of large consumers chose to make gas purchases from different

Table 13. EIA Natural Gas Data Sources

Data Category	Source	Geography	Frequency
Supply			
Reserves	EIA-23	U.S., States	A
Production	Voluntary reports of States and MMS to EIA on EIA-895	U.S., 33 States	A, M
Extraction Loss	EIA-64A	U.S., 33 States	A
Storage Injections and Withdrawals; Inventories	EIA-176; EIA-191	U.S., States	A, M
Disposition			
Residential Use	EIA-176; EIA-857	U.S., 50 States	A, M
Commercial Use	EIA-176; EIA-857	U.S., 50 States	A, M
Industrial Use	EIA-176; EIA-857	U.S., 50 States	A, M
Electric Utility Use	EIA-906	U.S., 50 States	A, M
Natural Gas Industry Use	EIA-176	U.S., 50 States	A
		U.S.	M (estimate)
Prices			
Wellhead	Voluntary reports of States and MMS to EIA on EIA-895	U.S., 33 States	A
		U.S.	M (estimate)
Citygate	EIA-176	U.S., 50 States	A
	EIA-857	U.S.	M
Residential, Commercial, Industrial	EIA-176; EIA-857	U.S., 50 States	A, M
Electric Utility	FERC-423; EIA-423	U.S., 50 States	A, M
Other			
Consumption and Fuel Switching Capability	EIA consumption surveys		Quadrennial
Major Firm Activities	EIA Financial Reporting System		A

A = Annual. M = Monthly.

Notes: EIA Forms include: EIA-23, “Annual Survey of Domestic Oil and Gas Reserves”; EIA-895, “Monthly Quantity and Value of Natural Gas Report”; EIA-64A, “Annual Report of the Origin of Natural Gas Liquids Production”; EIA-176, “Annual Report of Natural and Supplemental Gas Supply and Disposition”; EIA-191, “Monthly Underground Gas Storage Report”; EIA-857, “Monthly Report of Natural Gas Purchases and Deliveries to Consumers”; EIA-759, “Monthly Power Plant Report”; FERC-423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” Copies of forms and instructions are available on the EIA and FERC web sites.

Table 14. Examples of Other Natural Gas Data Sources

Data Category	Source	Geography	Frequency
Supply			
Gas Resources	U.S. Geological Survey, U.S. Department of Interior	Resource basins	As resource basin reviews are completed
Canadian Imports and Exports	Canadian National Energy Board	U.S.-Canada border	Monthly
Drilling Rig Activity	Baker-Hughes Survey	U.S.	Weekly
Storage Injections and Withdrawals	American Gas Association weekly survey through 2001; new EIA storage survey planned	U.S., 3 U.S. regions	Weekly
Prices			
Market Hubs	*Natural Gas Intelligence* and other proprietary sources	Market hubs	Daily for trading days
Futures Market Contract	New York Mercantile Exchange		Online minute to minute
Other			
Pipeline Capacity Release Trades	Pipeline online bulletin boards	Pipeline specific	Online minute to minute
Pipeline Operation Status	Office of Pipeline Safety, U.S. Department of Transportation	Pipeline specific	As needed because of operation events

suppliers and to purchase only transportation services from interstate pipelines and LDCs. More recently, State customer choice programs have offered similar options to residential and small commercial customers. Another important change has been the increased role of foreign trade in gas supply and disposition. Net natural gas imports were approximately 15 percent of U.S. natural gas consumption in 2000.

EIA's natural gas data collection instruments have changed as well. In 1980, EIA combined and expanded voluntary annual surveys that had been operated by the Bureau of Mines into the first mandatory survey. A new voluntary annual survey of State agencies was also initiated, to collect data on the quantities and values of natural gas produced. Storage information (first collected in the 1970s and 1980s in an annual survey jointly conducted by several agencies) was collected monthly beginning in 1991.[102] A monthly survey of deliveries to end-use sectors began in December 1984. The EIA surveys were redesigned over time to reflect changes in the regulation and operation of the industry, but changes in the surveys often lagged behind regulatory changes because of the time needed to identify new approaches, obtain revised collection authorities, and change survey instruments and processing and dissemination systems.

EIA's current natural gas data collection program remains basically an annual effort to obtain comprehensive information on natural gas volumes and prices. It has been expanded to provide more frequent, though less complete, monthly measurements and estimates of national and State data elements. Annual reports are received from more than 1,800 respondents representing the U.S. natural gas supply and disposition system. The national and State data are available about 9 months after the end of the reporting year. The monthly program provides estimates of major natural gas market activity measures approximately 60 to 90 days after the close of the reporting month, based on a combination of monthly surveys and estimation procedures.[103]

EIA's monthly data series have usually been reliable, consistent predictors of the final annual data series; however, the two sources share many of the same problems. For example, both have recently been less timely than in the past, and both have indicated larger than usual data problems through the size of their respective balancing items (see box on page 52). The balancing item is a calculated residual that represents the difference between measured supply and disposition of natural gas for a given time period, such as a month or year. The following sections provide an overview of major supply, demand, and price series and their primary data quality problems, with discussion of possible approaches to addressing the problems. EIA will be requesting comment on proposed changes to its natural gas data program during 2002.

Production

Natural gas sold for consumption—primarily methane—is produced either in a gaseous state or in solution with oil. The gas produced at the wellhead is a mixture of hydrocarbons and nonhydrocarbons. These "gross" gas volumes are subsequently reduced through a number of field processes. In some cases, operators re-inject a portion of the gas to maintain oil field pressure. A small portion may be vented and flared, almost exclusively for safety reasons. The nonhydrocarbons are removed sufficiently to comply with pipeline specifications. The gas volumes remaining after re-injection, venting, flaring, and nonhydrocarbon removal are described as "marketed" gas production. Because most "marketed" gas streams also contain heavier hydrocarbon gases such as ethane, butane, and propane, this "wet gas" is sent to a natural gas processing plant where the nonmethane hydrocarbons are removed. The resulting "dry gas" product is ready for transport to end users.

Due to the large cost of collecting and processing data from many thousands of natural gas producers, the annual and monthly measurement of marketed gas production is based on the voluntary annual and monthly reports provided on Form EIA-895, "Monthly Quantity and Value of Natural Gas Report," by the producing States and the Minerals Management Service (MMS) of the U.S. Department of Interior. Form EIA-895 is the successor to earlier voluntary annual reports and to a voluntary monthly report used until 1995 by the Interstate Oil and Gas Compact Commission (IOGCC) to prepare monthly State production estimates. EIA became responsible for monthly production estimates in January 1995. Data collection from the States is voluntary, because the Federal Government has no authority to require States to provide information.

The States and MMS are asked to submit data on several production activities in order to calculate "marketed production," the volume produced in a State or offshore region before the output is sent to a natural gas processing plant. The States and MMS collect and process data from producers for different reasons, including supporting their tax and royalty collection programs and administering natural resource or environmental management programs. The States and MMS process data from an estimated 22,000 operators of nearly 300,000 gas wells. They receive and process the information for revenue purposes, but the resulting reported sales volumes do

[102] Monthly storage reports had been requested in prior years on an annual survey.

[103] Estimates of more current activity are provided by the Short-Term Integrated Forecasting System and released in the *Short-Term Energy Outlook* and as preliminary estimates in the *Natural Gas Monthly*.

not necessarily represent production in the report period requested by EIA.

In most cases, monthly production data for the previous year are available to EIA by late summer of the following year; however, there are exceptions. Late and incomplete monthly reports are common. In addition, the State and Federal revenue forms are designed to provide information for basic revenue programs. They differ from State to State and often do not include all information elements requested by EIA. This frequently means that the elements used to calculate marketed production must be estimated by EIA from whatever data elements are submitted, from information included in State publications and web sites, from trade press, or from prior year data.

EIA has discussed the above issues with the data respondents. Some respondents have recommended that EIA use their web sites to obtain the most recent measures of sales volumes and revenues. Other analysts have suggested that EIA might process copies of the data

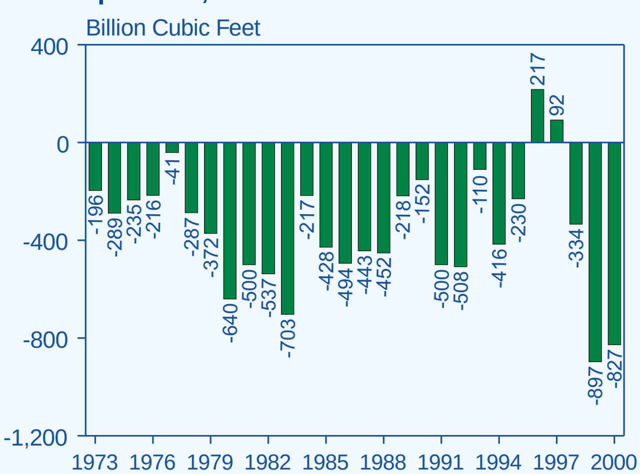
Balancing Items in EIA's Natural Gas Data Series

In an ideal statistical world, measured supply of natural gas would equal measured disposition (consumption). In a large and diverse national system of supply and disposition, however, the supply and disposition of natural gas cannot be tracked and measured exactly. When physical and statistical measurements of natural gas supply and disposition activities do not match, the difference is called the balancing item. The term is calculated as the difference, for a report period, between the sum of the components of supply and the sum of the components of natural gas disposition. The formula for the United States is:

(Dry gas production + Supplemental gaseous fuel supply + Net imports + Net storage withdrawals + Balancing item) = (Lease and plant fuel consumption + Pipeline fuel consumption + Residential, commercial, industrial, and electric utility consumption).

The balancing item may be positive or negative, because the sum of supply measures may be larger than the sum of disposition measures, or vice versa (see figure). The signs may change from month to month and year to year.

EIA Balancing Item for U.S. Natural Gas Supply and Disposition, 1973-2000



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

The difference between measured supply and disposition may be due to unmeasured sources of supply or disposition or to data reporting problems for any of the measured sources. The balancing item for any given year is customarily revised to a smaller value when final annual data replace the monthly data. One reason for this change is that several pieces of the supply and disposition system are only reported annually and are estimated for the more recent monthly periods. Another reason is that monthly consumption data series for end-use sectors are calculated from a sample of companies making end-use deliveries and include sampling uncertainty, whereas annual data are collected from all known respondents. Other reasons are that more time usually is available for the resolution of data quality and nonresponse issues for the annual series.

The annual balancing item has never been zero. The absolute values of annual balancing items since 1977 have ranged from 41 billion cubic feet (1977) to 897 billion cubic feet (1999). In most years the annual value has been negative, indicating that reported supply exceeded reported consumption. Within a given year, monthly balancing item measures are often positive in the early months but negative in the later months of the year. This pattern may relate to a lag in delivery reports during the peak winter heating season.

The balancing item measures for 2000 and the first three quarters of 2001 have been large and, in addition, have had opposite signs. Most analysts of natural gas industry trends in 2000 have assumed that consumption activity was underreported in 2000. For 2001, analysts have hypothesized that consumption estimates are too large and that production volumes are underreported. For the year 2000 and the first three quarters of 2001, the absolute values of the balancing items averaged 3.7 percent and 2.6 percent of total consumption, respectively. Those levels are significant when analysts seek to understand active, volatile markets.

provided by producers to the States and MMS or create an alternative monthly data collection process for some or all of the producing States. Those approaches would represent significant increases in the burden on producers and the resources required for EIA to obtain improved data series. Others have suggested that EIA should acknowledge the difficulties and change its program to estimate U.S. production on a monthly frequency using the best data available and collect and present State data only annually. EIA will request comments on these and other approaches during 2002.

Foreign Trade

Companies planning to import or export natural gas by pipeline or as liquefied natural gas (LNG) are required to obtain authorization from the Office of Fossil Energy, U.S. Department of Energy. As a condition for authorizations to import or export natural gas, companies must then file quarterly reports with the Office of Fossil Energy. The data are reported at a monthly level of detail. The compiled data are presented in the quarterly publication "Quarterly Natural Gas Import and Export Sales and Price Report" and provided to EIA in a quarterly computer file for presentation in the *Natural Gas Monthly*. Because data are available only once a quarter, they lag behind other monthly supply and disposition series. EIA prepares estimates or uses other sources to represent imports for the most recent months. For example, EIA uses the monthly data prepared by the National Energy Board of Canada to estimate imports and exports from Canada. There are no comparable data sources for LNG trade or trade with Mexico.

EIA has requested that the Office of Fossil Energy modify its data collection and processing program to provide monthly data reports. If this is not possible, EIA will pursue other sources and may request comments during 2002 on the option of creating a new EIA survey for imports and exports of LNG.

Storage Capacity and Activity

Natural gas is stored underground in depleted gas and oil fields, depleted aquifers, and salt caverns, as well as in aboveground LNG storage tanks. The volumes held in storage typically are withdrawn to supplement current gas production and imports during the winter, when gas demand peaks for residential and commercial customers. Storage volumes are rebuilt during the spring, summer, and fall, when gas demand is much lower.

The volume of natural gas held in underground storage facilities includes base gas and working gas. Base gas is held in permanent inventory to maintain adequate underground storage reservoir pressures and deliverability rates; working gas is held for withdrawal as needed. Volumes are also held in LNG storage tanks at import terminals, at peak shaving facilities associated with LDCs, and at other locations. LNG volumes are estimated to be about 4 to 5 percent of the volumes held in underground facilities, but they are important in some regional markets.

Data on base and working gas in underground storage are collected each month on a storage field and reservoir basis on Form EIA-191, "Monthly Underground Gas Storage Report." Storage levels are then published on a State basis. The monthly data are subsequently adjusted to correspond to data from Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," following publication of the *Natural Gas Annual*. There are occasional problems, because some respondents provide data about accounting transactions while others provide volumetric metering data, but the storage reports are the most timely of the monthly data series.

Reports collected on the annual Form EIA-176 also provide monthly data for the prior year on LNG storage injections and withdrawals at import terminals and at LDC peak shaving facilities. Data on LNG storage at facilities other than import terminals or LDC facilities are not collected on monthly or annual forms. EIA is currently studying the issue of whether monthly LNG storage inventories and activity are important to regional supplies and should be the subject of monthly data collections to improve the completeness and timeliness of storage measures.

In October 2001, Secretary of Energy Spencer Abraham directed EIA to begin a weekly gas storage survey in May 2002, after the American Gas Association (AGA) announced its intent to stop the weekly survey of natural gas storage it had been conducting since the beginning of 1994. AGA has collected weekly data from a sample of storage companies and estimated underground storage levels for the United States and three regions. The AGA survey has been widely followed by gas industry analysts and market participants, because it is the most timely gas market data series. EIA will issue a *Federal Register* notice in December 2001 describing the new survey.

Consumption Data

Natural gas is consumed in a variety of ways. Among its leading uses are space heating, cooking, operation of water heaters, industrial process heat, power generation, compressor operation, and as a feedstock in industrial and chemical processes such as fertilizer manufacture.

About four-fifths of gas consumption is measured monthly and annually by the reports of end-use deliveries to pipeline meters, as reported by LDCs and interstate and intrastate transmission pipelines. Monthly data are collected on Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers," from a sample of the LDCs and pipelines making deliveries to end users. Annual data are collected from all known delivery firms on Form EIA-176, "Annual Report of Natural Gas Supply and Disposition." The remaining gas consumption by electric utilities and the gas supply industry is collected in other ways. Gas used at electric utility plants is reported monthly by the plant operators on Form EIA-906, "Power Plant Report." In addition, the 8 to 9 percent of gas supply used in the production and transportation of natural gas (e.g., on leases, at processing plants, and in pipelines) is reported annually on Form EIA-176.

The collection of gas consumption data has been affected by the continuing restructuring of the natural gas and electricity generation industries, which started in the mid-1980s and mid-1990s, respectively. Industry changes have increased the difficulty of measuring total gas use accurately and assigning it to the appropriate end-use sector—residential, commercial, industrial, or electric utility. Issues include the following.

Traditional end-use sector definitions do not reflect changes in electricity generation. In 2000, approximately 3.05 trillion cubic feet of natural gas was consumed by electric utilities, according to data collected on EIA's "Monthly Power Plant Report." EIA's natural gas data publications use the data collected in the electric power data system for measures of fuel used at electric utilities. The low values in recent years for this portion of gas consumption reflect the declining role of electric utilities in electricity generation and the increasing role of independent power producers and cogenerators.

In 2000, nonutility generators used 3.29 trillion cubic feet—8 percent more gas than utility generators. Within the natural gas information system, nonutility generator and cogenerator gas use is reported in the industrial or commercial sector, depending on the nature of the firm. Other EIA information sources are combining data from the electric power data system for fuel used by plants engaged entirely in electricity generation (electric utilities and independent power producers) for a fuller measure of fuel used in electricity generation. However, fuel use data are not currently available for cogenerators.

EIA is studying how to divide fuel use by cogenerators to distinguish electricity use and other uses in those sectors. Gas used at cogenerators is reported in the gas data system in the sector that most closely corresponds to the primary line of business of the cogenerator firm. For example, gas used at an automobile plant that generated electricity and sold a portion to the grid would be measured as use in the industrial sector, but gas used at a hospital or university that generated electricity and sold a portion would be measured as use in the commercial sector. EIA is working to develop an approach to better measurement of fuel use for electricity generation from all nonutility generators. Identifying end uses accurately will help analysts determine the economic effects of fuel price changes.

Firms providing natural gas delivery do not know the intended use for delivered gas. When gas pipelines and LDCs owned the gas they delivered, their customer billing records provided information about the purchasing firms, from which the intended end use of the delivered gas might be deduced. The delivery firms were able to report to EIA the volumes delivered in each State to residential, commercial, and industrial customer groups. Now, pipeline firms and LDCs frequently provide gas delivery services at the direction of an intermediate party handling purchasing for the final customers, and they often do not have information about customers to use in assigning deliveries to end-use sectors.

The extent of the problem varies from sector to sector. LDCs continue to sell natural gas to residential and many commercial customers in most States, and hence they have information about customers which they use to identify volume and price information affecting those end-use customer groups. Interstate and intrastate pipelines, however, often are providing only transportation services from point to point in transactions arranged by someone other than the final user of the gas. This means the deliverers to the drop-off meter do not know the identity or sector of the firm using the gas.

Two illustrations may demonstrate the complexity of correctly assigning gas use to end-use sectors even when the general identity of the user is known:

1. A State University takes gas from a single pipeline inlet but uses some of that gas to heat dormitories (a residential sector use), some to heat classrooms (a commercial sector use), and some to generate electricity for campus use.
2. A building in a metropolitan area also takes gas from a single pipeline supplier, but the building provides both condominium (residential sector) and office (commercial sector) space.

Pipelines and distribution companies are asked to assign all gas use to the category in which the predominant usage occurred, but this may be difficult to determine.

A related problem is that many pipeline companies are incorrectly reporting the end-use deliveries made from their systems as commercial sector deliveries, because the marketing firms that purchased the delivery services are defined as part of the commercial sector. Other pipeline companies are reporting sales transactions data—i.e., volumes sold to marketers—as deliveries to commercial sector end users. Because gas is frequently sold and resold as it moves through pipelines, such misunderstandings can lead to overstatement of deliveries.

Changes in the natural gas industry have had several significant effects on data quality. The natural gas industry has grown and restructured in recent years as it moved away from its past, more regulated structure. New unregulated firms and unregulated subsidiaries of existing firms have created new business practices. These changes have affected the business records that the firms must legally maintain and report to regulatory agencies. The types of information previously created for regulatory requirements, and thus easily available for reporting to EIA, are no longer available, and the staff that once prepared the regulatory reports and similar EIA reports are no longer allocated to those functions. Together these changes have resulted in increased problems for EIA data quality and completeness. In recent years more respondents are providing late and problem data. As a result, summary data from several States have not been acceptable for publication in a timely fashion. EIA has had to increase its data quality efforts to reduce this problem.

There have also been large numbers of new firms, business sales, reorganizations, and mergers during this period. EIA has sought to keep abreast of these changes by maintaining a current list of appropriate survey respondents. To maintain the respondent population for its Form EIA-176 survey, EIA must track changes in the business activities (storage, end-use deliveries, and shipments) of all gas firms in all States. During this period of change, the task has been difficult. Not all new firms or new operations for merged or reorganized firms may have been identified. EIA has recently expanded its efforts to maintain a complete frame of gas supply and disposition companies. Staff at newly identified or reorganized offices have also found it difficult to provide meaningful data to EIA for many reasons. One of these has been the complexity and content of the EIA-176 survey instrument itself, which is now 6 pages long and requires 15 pages of instructions.

EIA believes that its annual and monthly natural gas data collection forms will need to be simplified and redesigned to reflect current industry operations and minimize respondent burden and confusion. EIA will provide a proposal for simplification and request comments on this and other approaches to collect meaningful, timely, and accurate data. Several suggestions have already been provided to EIA, including proposals for simplification of the consumption forms and instructions, and changing the collection targets to correspond to current business records.

Prices

In addition to the data series reporting natural gas volumes, EIA also provides several monthly price data series and corresponding annual revisions. The current surveys were developed to capture prices during the previous month at three significant points in the supply chain of the industry. The “wellhead” price is the first price in the supply chain measured by EIA. It is intended to represent the value of marketed gas production in producing States. The “citygate” price represents the price at the point of entry to LDC systems. The “consumption” prices provided by EIA are the prices of gas sold and delivered by pipelines and LDCs to end-use customers in the residential, commercial, industrial, and electric utility sectors. Prices paid by electric utilities to acquire gas for utility generation are collected directly from the utilities on electric power data forms, and the other end-use prices are collected on natural gas data forms. The price data assist in the interpretation and measurement of energy supply and demand. However, industry restructuring has changed the business records used by respondents and limited respondents’ ability to provide useful data. Some of these issues are described below.

Wellhead prices are intended to represent the value of marketed gas production. As noted above, marketed gas production is the volume of “wet gas” produced. The data series is calculated for the United States and individual producing States from voluntary reports received from the States and the MMS. EIA requests information on the volume and value of marketed gas production but recognizes that the States and MMS do not always use this point in the supply chain for their valuation. In those instances, EIA asks the respondents to provide available value data and a validated quantity for each month. Given the differences in the point at which valuation of gas for tax and royalty purposes occurs, as well as the treatment of such monetary elements as taxes and other fees, EIA must make adjustments to reach a common definition across States. In addition, because data are not provided for most States until months after the requested report date (the 20th day after the end of the report month), EIA uses an estimation procedure for the U.S. average wellhead prices until complete data reports are received from the States.[104] Most of the respondents have provided data by the release date of the *Natural Gas Annual*, approximately 9 months after the end of the report year. A revised U.S. estimate and State data are presented in the *Natural Gas Annual*, but the data may continue to be revised for another year.

Citygate prices are reported monthly and annually for each State. The monthly prices are based on monthly data collected on Form EIA-857 from a sample of LDCs

[104]The methodology for monthly estimation of the average U.S. wellhead price is presented in the *Natural Gas Monthly*, Appendix A, Note 8.

in each State. Annual prices are based on data provided by all LDCs on Form EIA-176. Respondents are asked to report the cost to them of purchased gas received in the distribution service area. The price series has traditionally been contrasted to the prices paid by final users to illustrate the relative shares of final user prices associated with each stage of the supply chain. Because LDCs are the respondents providing citygate price information, the term is meaningful only for analyzing possible costs and profits of gas purchased from the LDCs. The citygate price is not meaningful for understanding fuel costs in the industrial and electric utility sectors, because most gas delivered to those sectors is not purchased through LDCs.

End-use sector prices are also provided monthly and annually for each State. The monthly prices for the residential, commercial, and industrial sectors are calculated from data collected on Form EIA-857 from a sample of LDCs and interstate and intrastate pipelines making deliveries to end users. The monthly price for deliveries to the electric utility sector is based on data collected on the electricity survey Form EIA-906, "Power Plant Report."[105] Respondents are asked to report revenues and associated sales volumes to determine unit prices. Annual data for the residential, commercial, and industrial sectors are derived from Form EIA-176 data; annual data for the electricity sector are derived from revisions to the electricity form (EIA-906).

There are a number of concerns about EIA's natural gas price series. Most are related to the changing operation of the industry since restructuring. For price data, just as for volume data, the fact that pipelines and LDCs no longer know the purchasers and purchase terms for large volumes of gas sold means that data collected from them are less representative for measuring the average price of all final deliveries.

After FERC Order 436 was issued in 1985, large consumers of natural gas began to purchase natural gas directly from producers or in market hub transactions. They no longer purchased the commodity from the LDCs and interstate pipelines. The pipeline companies and LDCs completing EIA surveys knew only the price of gas purchased directly from them, and their direct sales have fallen from 75 percent of total gas delivered to industrial customers in 1984 to 15 to 18 percent of all industrial sales in the late 1990s (Figure 26).

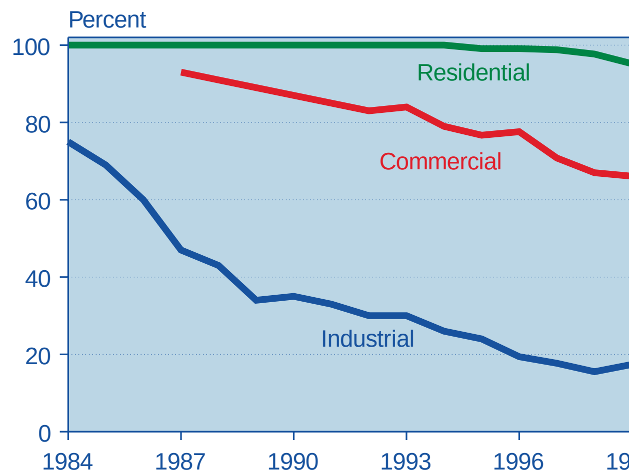
EIA has continued to use the price information collected from LDCs and intrastate pipelines to measure industrial sector prices. Because these prices probably represent smaller industrial customers, it is likely that the reported sector prices are higher than the actual average industrial price. EIA explored the idea of measuring prices paid by firms in the industrial sector through the direct collection of price data from gas customers who were respondents to the U.S. Survey of Manufactures conducted each month by the Bureau of the Census. However, this approach for collecting price data from industrial gas customers rather than gas suppliers would cost more than the natural gas data program could afford.

As residential and commercial sector customer choice programs grow, a similar problem might develop for measuring end-use prices in those sectors, because residential and commercial customers can now purchase the commodity and the transportation services separately. EIA is currently implementing a new survey in Georgia, Maryland, New York, Ohio, and Pennsylvania to determine whether price data collected from marketing firms will sustain and improve the quality of residential and commercial sector price data in customer choice States. EIA is examining how to combine the commodity and transportation price data from marketers and LDCs to create an end-use price.

A problem shared by citygate and end-use price series is the fact that most natural gas transactions are conducted on the basis of heat content. Heat content is measured in British thermal units (Btu) or therms.[106] EIA has continued to request volume data measured in thousand cubic feet and has asked for the average Btu content of gas delivered to customers to assist in conversions. These adjustments, however, provide an opportunity for misreporting and error.

A number of suggestions have been made to improve natural gas price data. For the most part the suggestions continue to focus on collecting data from the natural gas

Figure 26. Market Coverage of U.S. Natural Gas Prices in EIA Surveys, 1984-1999



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

[105] Data for the years before 2001 were collected on Form EIA-759, "Monthly Power Plant Report."

[106] A therm is equal to 100,000 Btu.

industry, which includes fewer collection points than collecting data from customers. Suggestions for improving information from the gas industry include changing from an end-use sector orientation for data to an orientation that corresponds with the tariff data that industry can easily provide. Such a change might mean that price data would be available according to size of purchase or terms of service, not sector. Another suggestion is to pursue complementary forms for marketers and delivery firms to capture the price of delivered gas to customers for both groups; however, the possibility of mixing transactions data with final delivery data could be significant.

Opportunities for Change

The review of EIA's major data series indicates a number of challenges to the scope and quality of current natural gas data. Several were recognized previously, when EIA developed a program in the late 1990s to redesign its natural gas information program to reflect the restructuring of the industry and to meet customer needs in the post-2000 time frame. The Next Generation*Natural Gas (NG2) project included efforts to identify and address data quality problems for current price and volume series and to identify requirements for new kinds of data. Another issue raised during the NG2 focus group sessions was a concern that EIA data on prices and volumes needed to be more timely, because the natural gas market is no longer based in long-term contracts. Greater data timeliness and accuracy were emphasized more than developing new data elements. EIA believes it must determine how quality and timeliness for major components of current programs can be maintained or improved and what tradeoffs between accuracy and timeliness must be addressed before new data collection proposals are considered.

EIA data collection programs operate under authority granted in the Federal Energy Administration Act (Public Law 93-275). Approximately every 3 years, each data program must be reviewed by the Office of Management and Budget to determine that the program conforms to this authority, meets information needs, and represents the minimum paperwork burden for respondents. During the review the public is asked to comment on the current and proposed surveys. Because authority for the current natural gas data collection program expires at the end of 2002, EIA will be proposing a number of changes in the program during the coming year. EIA will invite suggestions and comment on many of the issues discussed in this chapter.

Appendix A

Memorandum from the Secretary of Energy

The Secretary of Energy
Washington, DC 20585

April 25, 2001

MEMORANDUM FOR LARRY PETTIS, ACTING ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

FROM: SPENCER ABRAHAM Spencer Abraham

SUBJECT: Natural Gas Study

I have received numerous requests for information on natural gas markets from Governors, Members of Congress, and State legislators. Specifically, they have expressed concern about tight supplies, volatile prices, and regional price disparities. At the same time, the role of natural gas in the development of a National Energy Policy has become increasingly important due to its expanded use in the generation of electricity. Given these circumstances, I requested that the Energy Information Administration (EIA) conduct an independent study of North American natural gas markets. This memo is to serve as a formal record of that request.

The study should be in two parts: part one will be a short-term study to address the present need for timely information; and part two will address longer term issues. The short-term study should include:

1) trends in national demand, supply, transmission, and storage that have affected price;
2) circumstances leading to regionally higher prices in areas such as California and an analysis of regional price differences;
3) drilling activity in response to higher prices; and
4) EIA's short and long-term natural gas forecast, including imports from Canada, Mexico, and LNG.

The following topics should be considered in the long-term study:

1) evidence of supply response to drilling activity;
2) conditions required for additional LNG facilities to feed U.S. markets;
3) effect on supply and prices if limits to access on Federal lands are removed; and
4) areas in which further analysis or improved data are necessary to understand market trends.

The short-term study should be completed by the end of April 2001 and the long-term study should be completed by the end of October 2001. Your efforts in developing this independent analysis to shed light on natural gas markets and help guide us in our policy making efforts are much appreciated.

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Appendix B

Model Results:
Reference Case Comparisons

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000	Projections							
		2005				2010			
		Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access
Production									
Crude Oil and Lease Condensate	12.33	11.38	11.38	11.38	11.30	10.76	10.76	11.09	11.02
Natural Gas Plant Liquids	2.71	3.02	3.02	3.02	3.02	3.37	3.39	3.37	3.39
Dry Natural Gas	19.59	21.29	21.34	21.31	21.34	24.12	24.22	24.15	24.28
Coal	22.58	24.95	24.95	24.97	24.97	26.23	26.27	26.27	26.26
Nuclear Power	8.03	8.10	8.10	8.10	8.10	7.87	7.87	7.87	7.87
Renewable Energy[1]	6.46	7.37	7.37	7.37	7.37	7.89	7.87	7.88	7.87
Other[2]	1.10	0.68	0.70	0.66	0.67	0.85	0.85	0.86	0.84
Total	**72.80**	**76.79**	**76.86**	**76.79**	**76.78**	**81.09**	**81.23**	**81.50**	**81.54**
Imports									
Crude Oil[3]	19.69	22.63	22.60	22.65	22.70	24.36	24.36	24.16	24.20
Petroleum Products[4]	4.73	5.68	5.71	5.71	5.71	7.83	7.81	7.74	7.75
Natural Gas	3.85	5.01	5.01	5.02	5.00	5.64	5.59	5.64	5.58
Other Imports[5]	0.76	1.07	1.08	1.09	1.08	0.95	0.96	0.96	0.95
Total	**29.04**	**34.39**	**34.40**	**34.45**	**34.49**	**38.79**	**38.71**	**38.50**	**38.49**
Exports									
Petroleum[6]	2.15	1.70	1.69	1.70	1.69	1.91	1.90	1.91	1.91
Natural Gas	0.25	0.41	0.41	0.41	0.41	0.63	0.63	0.63	0.63
Coal	1.53	1.41	1.41	1.41	1.41	1.36	1.44	1.44	1.44
Total	**3.93**	**3.52**	**3.51**	**3.52**	**3.51**	**3.90**	**3.96**	**3.98**	**3.98**
Discrepancy[7]	**-1.37**	**0.04**	**0.06**	**0.03**	**0.05**	**0.37**	**0.36**	**0.41**	**0.38**
Consumption									
Petroleum Products[8]	38.63	41.40	41.42	41.43	41.43	45.20	45.20	45.21	45.21
Natural Gas	23.43	26.16	26.20	26.17	26.19	28.85	28.91	28.89	28.95
Coal	22.34	24.03	24.04	24.06	24.06	25.41	25.38	25.38	25.38
Nuclear Power	8.03	8.10	8.10	8.10	8.10	7.87	7.87	7.87	7.87
Renewable Energy[1]	6.48	7.37	7.37	7.37	7.37	7.90	7.88	7.89	7.88
Other[9]	0.38	0.55	0.56	0.56	0.56	0.38	0.39	0.38	0.38
Total	**99.29**	**107.61**	**107.69**	**107.70**	**107.71**	**115.61**	**115.62**	**115.61**	**115.67**
Net Imports - Petroleum	**22.28**	**26.61**	**26.62**	**26.65**	**26.71**	**30.29**	**30.27**	**29.99**	**30.05**
Prices (2000 dollars per unit)									
World Oil Price (dollars per barrel)[10]	27.72	22.73	22.73	22.73	22.73	23.36	23.36	23.36	23.36
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.60	2.66	2.66	2.67	2.65	2.85	2.80	2.83	2.78
Coal Minemouth Price (dollars per ton)	16.45	14.99	15.07	14.97	15.04	14.11	13.88	13.83	13.85
Average Electricity Price (cents per kilowatthour)	6.9	6.4	6.4	6.4	6.4	6.3	6.3	6.3	6.3

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals and heat loss when natural gas is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
OCS = Outer continental shelf.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000). **Projections:** EIA, AEO2002 National Energy Modeling System runs AEO2002.D102001B, ACCRM.D111101A, ACCOFF.D111101A, ACCREF.D111101A.

Supply, Disposition, and Prices	Projections							
	2015				2020			
	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access
Production								
Crude Oil and Lease Condensate	11.76	11.76	12.29	12.24	11.92	11.90	12.44	12.44
Natural Gas Plant Liquids	3.74	3.76	3.75	3.77	4.03	4.07	4.05	4.10
Dry Natural Gas	27.03	27.16	27.14	27.30	29.25	29.50	29.49	29.84
Coal	26.91	26.93	27.00	26.86	28.11	28.12	28.06	27.94
Nuclear Power	7.55	7.55	7.55	7.55	7.49	7.49	7.49	7.49
Renewable Energy[1]	8.47	8.45	8.46	8.45	8.93	8.92	8.96	8.90
Other[2]	1.04	1.04	1.04	1.02	0.93	0.94	0.95	1.04
Total	**86.51**	**86.64**	**87.22**	**87.19**	**90.66**	**90.95**	**91.45**	**91.75**
Imports								
Crude Oil[3]	24.04	24.05	23.58	23.65	24.45	24.44	23.86	24.07
Petroleum Products[4]	10.31	10.27	10.34	10.29	12.69	12.64	12.73	12.43
Natural Gas	6.04	5.97	5.97	5.94	6.20	6.08	6.13	6.01
Other Imports[5]	1.07	1.07	1.07	1.07	1.09	1.09	1.10	1.08
Total	**41.46**	**41.35**	**40.97**	**40.94**	**44.44**	**44.25**	**43.82**	**43.58**
Exports								
Petroleum[6]	2.02	2.01	2.04	2.03	2.11	2.10	2.12	2.13
Natural Gas	0.66	0.66	0.66	0.66	0.56	0.56	0.56	0.56
Coal	1.34	1.34	1.34	1.34	1.38	1.38	1.38	1.37
Total	**4.01**	**4.01**	**4.03**	**4.03**	**4.05**	**4.05**	**4.07**	**4.06**
Discrepancy[7]	**0.32**	**0.31**	**0.36**	**0.35**	**0.20**	**0.21**	**0.25**	**0.28**
Consumption								
Petroleum Products[8]	48.85	48.84	48.89	48.87	51.99	51.97	51.96	51.96
Natural Gas	32.14	32.19	32.18	32.30	34.63	34.74	34.78	35.01
Coal	26.16	26.18	26.25	26.11	27.35	27.37	27.31	27.19
Nuclear Power	7.55	7.55	7.55	7.55	7.49	7.49	7.49	7.49
Renewable Energy[1]	8.48	8.46	8.46	8.46	8.94	8.93	8.97	8.91
Other[9]	0.46	0.46	0.46	0.46	0.44	0.44	0.45	0.43
Total	**123.64**	**123.68**	**123.79**	**123.75**	**130.85**	**130.94**	**130.96**	**130.99**
Net Imports - Petroleum	**32.33**	**32.31**	**31.88**	**31.91**	**35.04**	**34.98**	**34.47**	**34.37**
Prices (2000 dollars per unit)								
World Oil Price (dollars per barrel)[10] . . .	24.00	24.00	24.00	24.00	24.68	24.68	24.68	24.68
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11] . . .	3.07	3.04	3.04	3.02	3.26	3.20	3.22	3.15
Coal Minemouth Price (dollars per ton)	13.44	13.48	13.55	13.56	12.79	12.92	12.87	12.92
Average Electricity Price (cents per kilowatthour)	6.3	6.3	6.3	6.3	6.5	6.5	6.5	6.4

Table B2. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2000	Projections							
		2005				2010			
		Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access
Production									
Dry Gas Production[1]	19.08	20.73	20.78	20.75	20.77	23.48	23.59	23.52	23.64
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Net Imports	**3.52**	**4.50**	**4.50**	**4.50**	**4.49**	**4.89**	**4.84**	**4.89**	**4.83**
Canada	3.46	4.08	4.08	4.09	4.07	4.51	4.46	4.51	4.45
Mexico	-0.09	-0.22	-0.22	-0.22	-0.22	-0.45	-0.45	-0.45	-0.45
Liquefied Natural Gas	0.16	0.64	0.64	0.64	0.64	0.83	0.83	0.83	0.83
Total Supply	**22.69**	**25.35**	**25.38**	**25.36**	**25.38**	**28.49**	**28.54**	**28.52**	**28.58**
Consumption by Sector									
Residential	5.00	5.37	5.38	5.37	5.38	5.53	5.54	5.53	5.54
Commercial	3.27	3.67	3.67	3.67	3.67	3.93	3.94	3.93	3.94
Industrial[3]	8.41	8.89	8.90	8.88	8.89	9.39	9.40	9.40	9.40
Electric Generators[4]	4.24	5.48	5.50	5.49	5.50	6.85	6.87	6.87	6.89
Lease and Plant Fuel[5]	0.02	0.06	0.06	0.06	0.06	0.09	0.09	0.09	0.09
Pipeline Fuel	0.77	0.77	0.78	0.78	0.78	0.84	0.84	0.84	0.84
Transportation[6]	1.12	1.25	1.25	1.25	1.25	1.50	1.50	1.51	1.51
Total	**22.83**	**25.50**	**25.54**	**25.51**	**25.53**	**28.13**	**28.18**	**28.16**	**28.22**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**-0.14**	**-0.15**	**-0.15**	**-0.14**	**-0.15**	**0.36**	**0.36**	**0.36**	**0.36**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2000 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.

Sources: 2000 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 transportation sector consumption: EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. Other 2000 consumption: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System runs AEO2002.D102001B, ACCRM.D111101A, ACCOFF.D111101A, ACCREF.D111101A.

Supply and Disposition	Projections							
	2015				2020			
	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access
Production								
Dry Gas Production[1]	26.32	26.44	26.42	26.58	28.48	28.72	28.72	29.06
Supplemental Natural Gas[2]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Net Imports	**5.26**	**5.18**	**5.19**	**5.16**	**5.51**	**5.39**	**5.44**	**5.32**
Canada	4.90	4.83	4.84	4.80	5.06	4.94	4.99	4.87
Mexico	-0.47	-0.47	-0.47	-0.47	-0.38	-0.38	-0.38	-0.38
Liquefied Natural Gas	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83
Total Supply	**31.69**	**31.74**	**31.73**	**31.85**	**34.10**	**34.23**	**34.26**	**34.49**
Consumption by Sector								
Residential	5.73	5.74	5.74	5.74	5.98	6.00	5.99	6.01
Commercial	4.21	4.22	4.22	4.22	4.52	4.53	4.52	4.54
Industrial[3]	9.79	9.81	9.80	9.80	10.06	10.09	10.10	10.17
Electric Generators[4]	8.91	8.91	8.90	8.99	10.30	10.32	10.34	10.44
Lease and Plant Fuel[5]	0.12	0.12	0.12	0.12	0.14	0.14	0.14	0.14
Pipeline Fuel	0.93	0.93	0.92	0.93	0.99	1.00	0.99	1.00
Transportation[6]	1.66	1.67	1.69	1.70	1.80	1.81	1.83	1.85
Total	**31.34**	**31.39**	**31.38**	**31.50**	**33.78**	**33.89**	**33.92**	**34.15**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.35**	**0.35**	**0.34**	**0.35**	**0.32**	**0.34**	**0.34**	**0.34**

Table B3. Natural Gas Supply, Prices, Reserves, and Reserve Additions

Production, Prices, and Reserves	2000	Projections							
		2005				2010			
		Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access
Lower 48 Average Wellhead Price[1] (2000 dollars per thousand cubic feet)	**3.60**	**2.66**	**2.66**	**2.67**	**2.65**	**2.85**	**2.80**	**2.83**	**2.78**
Dry Production (trillion cubic feet)[2]									
U.S. Total	**19.08**	**20.73**	**20.78**	**20.75**	**20.77**	**23.48**	**23.59**	**23.52**	**23.64**
Lower 48 Onshore	13.31	14.36	14.41	14.37	14.41	16.45	16.57	16.40	16.53
Associated-Dissolved[3]	1.79	1.63	1.63	1.63	1.63	1.43	1.43	1.43	1.43
Non-Associated	11.52	12.73	12.78	12.74	12.77	15.02	15.14	14.97	15.10
Conventional	6.89	6.92	6.92	6.93	6.92	7.89	7.84	7.86	7.82
Unconventional	4.63	5.81	5.86	5.81	5.86	7.13	7.30	7.10	7.28
Lower 48 Offshore	5.34	5.87	5.87	5.87	5.87	6.50	6.48	6.59	6.57
Associated-Dissolved[3]	1.16	1.19	1.19	1.19	1.19	1.22	1.22	1.24	1.24
Non-Associated	4.18	4.68	4.68	4.68	4.68	5.28	5.26	5.34	5.33
Alaska	0.43	0.50	0.50	0.50	0.50	0.53	0.53	0.53	0.53
Lower 48 End of Year Dry Reserves[2] (trillion cubic feet)	**162.31**	**167.16**	**168.41**	**167.12**	**168.43**	**174.09**	**176.80**	**176.67**	**179.27**
Supplemental Gas Supplies[4]	**0.10**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Lower 48 Wells (thousands)	**24.05**	**23.34**	**23.88**	**23.34**	**23.88**	**24.32**	**24.54**	**24.35**	**24.57**
Lower 48 Dry Natural Gas Reserves (trillion cubic feet)									
Lower 48 Total	162.3	167.2	168.4	167.1	168.4	174.1	176.8	176.7	179.3
Lower 48 Onshore	132.2	133.1	134.4	133.1	134.4	139.6	142.2	139.7	142.2
Associated-Dissolved[3]	15.0	13.7	13.7	13.7	13.7	12.0	12.0	12.0	12.0
Non-Associated	117.2	119.4	120.7	119.4	120.7	127.6	130.2	127.7	130.2
Conventional	64.0	60.8	60.8	60.7	60.8	62.4	62.5	62.4	62.6
Unconventional	53.1	58.7	59.9	58.6	59.9	65.2	67.7	65.3	67.6
Lower 48 Offshore	30.1	34.0	34.0	34.0	34.0	34.5	34.6	37.0	37.1
Associated-Dissolved[3]	7.0	7.2	7.2	7.2	7.2	7.3	7.3	7.5	7.5
Non-Associated	23.2	26.9	26.9	26.9	26.9	27.2	27.2	29.5	29.6
Lower 48 Dry Natural Gas Reserve Additions (trillion cubic feet)									
Lower 48 Total	22.5	22.3	22.8	22.3	22.8	23.8	24.1	24.8	25.1
Lower 48 Onshore	17.1	15.5	15.9	15.5	15.9	17.9	18.2	17.9	18.2
Associated-Dissolved[3]	1.2	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2
Non-Associated	15.8	14.4	14.9	14.4	14.9	16.7	17.0	16.7	17.0
Conventional	9.6	6.8	6.8	6.8	6.8	8.5	8.5	8.5	8.5
Unconventional	6.2	7.6	8.0	7.6	8.0	8.3	8.6	8.3	8.5
Lower 48 Offshore	5.4	6.8	6.8	6.8	6.8	5.9	5.9	6.8	6.8
Associated-Dissolved[3]	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3
Non-Associated	4.4	5.7	5.7	5.7	5.7	4.7	4.7	5.5	5.5

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[4]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). 2000 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Other 2000 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System runs AEO2002.D102001B, ACCRM.D111101A, ACCOFF.D111101A, ACCREF.D111101A.

Production, Prices, and Reserves	Projections							
	2015				2020			
	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access
Lower 48 Average Wellhead Price[1]								
(2000 dollars per thousand cubic feet)	**3.07**	**3.04**	**3.04**	**3.02**	**3.26**	**3.20**	**3.22**	**3.15**
Dry Production (trillion cubic feet)[2]								
U.S. Total	**26.32**	**26.44**	**26.42**	**26.58**	**28.48**	**28.72**	**28.72**	**29.06**
Lower 48 Onshore	19.40	19.56	19.12	19.30	21.13	21.38	20.88	21.22
Associated-Dissolved[3]	1.37	1.37	1.37	1.37	1.36	1.36	1.36	1.36
Non-Associated	18.04	18.19	17.75	17.93	19.77	20.02	19.52	19.85
Conventional	9.94	9.83	9.70	9.66	10.77	10.70	10.65	10.63
Unconventional	8.09	8.37	8.06	8.27	8.99	9.32	8.87	9.23
Lower 48 Offshore	6.35	6.31	6.73	6.71	6.75	6.74	7.23	7.24
Associated-Dissolved[3]	1.27	1.27	1.33	1.33	1.25	1.25	1.30	1.30
Non-Associated	5.08	5.04	5.40	5.39	5.50	5.49	5.92	5.93
Alaska	0.57	0.57	0.57	0.57	0.60	0.60	0.60	0.60
Lower 48 End of Year Dry Reserves[2]								
(trillion cubic feet)	**181.49**	**185.37**	**186.67**	**190.48**	**187.79**	**193.28**	**194.27**	**199.13**
Supplemental Gas Supplies[4]	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Lower 48 Wells (thousands)	**25.55**	**25.73**	**25.22**	**25.69**	**33.08**	**33.89**	**32.33**	**32.81**
Lower 48 Dry Natural Gas Reserves								
(trillion cubic feet)								
Lower 48 Total	181.5	185.4	186.7	190.5	187.8	193.3	194.3	199.1
Lower 48 Onshore	146.7	150.6	147.4	151.2	155.3	160.7	156.4	161.1
Associated-Dissolved[3]	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.4
Non-Associated	135.2	139.1	135.9	139.7	143.8	149.2	144.9	149.7
Conventional	65.4	66.3	66.3	66.8	66.1	67.2	67.7	68.3
Unconventional	69.8	72.8	69.6	72.9	77.8	82.0	77.3	81.4
Lower 48 Offshore	34.8	34.8	39.3	39.3	32.5	32.6	37.9	38.0
Associated-Dissolved[3]	7.6	7.6	8.0	8.0	7.5	7.5	7.8	7.8
Non-Associated	27.1	27.1	31.3	31.3	25.0	25.1	30.0	30.2
Lower 48 Dry Natural Gas Reserve Additions								
(trillion cubic feet)								
Lower 48 Total	27.0	27.8	28.6	29.1	28.2	28.7	28.6	28.9
Lower 48 Onshore	20.6	21.0	20.5	20.9	22.3	22.8	22.1	22.5
Associated-Dissolved[3]	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4
Non-Associated	19.3	19.6	19.2	19.6	20.9	21.4	20.7	21.1
Conventional	10.5	10.5	10.4	10.4	10.5	10.5	10.5	10.5
Unconventional	8.8	9.2	8.7	9.1	10.4	10.9	10.2	10.6
Lower 48 Offshore	6.4	6.8	8.1	8.2	5.9	5.9	6.5	6.5
Associated-Dissolved[3]	1.5	1.5	1.5	1.5	1.1	1.1	1.1	1.1
Non-Associated	4.9	5.4	6.6	6.7	4.8	4.8	5.3	5.3

Table B4. Lower 48 Natural Gas Production and Wellhead Prices by Supply Region

Production and Prices	2000	Projections							
		2005				2010			
		Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access
Dry Production (trillion cubic feet)[1]									
Lower 48 Total	18.65	20.23	20.28	20.25	20.28	22.95	23.05	22.98	23.10
Lower 48 Onshore									
Northeast	0.93	1.14	1.14	1.13	1.14	1.46	1.50	1.46	1.49
Gulf Coast	4.81	5.02	5.02	5.03	5.02	5.47	5.45	5.46	5.44
Midcontinent	2.58	2.86	2.86	2.86	2.86	3.05	3.03	3.04	3.03
Southwest	1.61	1.55	1.55	1.55	1.55	1.87	1.85	1.87	1.85
Rocky Mountain	3.08	3.46	3.51	3.47	3.51	4.24	4.38	4.21	4.36
West Coast	0.31	0.33	0.33	0.33	0.33	0.36	0.36	0.36	0.36
Lower 48 Offshore									
Gulf	5.28	5.81	5.81	5.82	5.82	6.44	6.42	6.47	6.46
Pacific	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.10	0.10
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02
Natural Gas Wellhead Prices (2000 dollars per thousand cubic feet)									
Lower 48 Average	3.60	2.66	2.66	2.67	2.65	2.85	2.80	2.83	2.78
Lower 48 Onshore									
Northeast	4.17	2.94	2.94	2.95	2.94	3.19	3.14	3.18	3.13
Gulf Coast	3.74	2.68	2.68	2.68	2.68	2.80	2.77	2.80	2.77
Midcontinent	3.56	2.72	2.72	2.72	2.72	2.87	2.84	2.87	2.83
Southwest	3.71	2.66	2.65	2.66	2.65	2.76	2.75	2.75	2.74
Rocky Mountain	3.26	2.59	2.56	2.60	2.55	2.70	2.58	2.67	2.57
West Coast	3.76	3.03	3.03	3.05	3.02	3.00	2.91	2.96	2.89
Lower 48 Offshore									
Gulf	3.54	2.59	2.59	2.59	2.59	2.93	2.89	2.90	2.87
Pacific	4.26	2.89	2.88	2.91	2.88	3.22	3.12	1.17	1.15
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[1]Marketed production (wet) minus extraction losses.

Note: Supply regions are defined in *Documentation of the Oil and Gas Supply Module*, Energy Information Administration (EIA), DOE/EIA-M063(2000) (Washington, DC, January 2000). Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.

Sources: 2000: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Projections: EIA, AEO2001 National Energy Modeling System runs AEO2002.D102001B, ACCRM.D111101A, ACCOFF.D111101A, ACCREF.D111101A.

Production and Prices	Projections							
	2015				2020			
	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access	Reference	Reference with Rocky Mountain Access	Reference with OCS Access	Reference with Rocky Mountain and OCS Access
Dry Production (trillion cubic feet)[1]								
Lower 48 Total	25.75	25.87	25.85	26.01	27.88	28.12	28.11	28.45
Lower 48 Onshore								
Northeast	1.81	1.88	1.81	1.86	2.19	2.27	2.14	2.22
Gulf Coast	6.65	6.53	6.45	6.44	6.64	6.62	6.57	6.58
Midcontinent	3.47	3.45	3.43	3.41	3.83	3.78	3.79	3.76
Southwest	2.12	2.09	2.12	2.09	2.28	2.26	2.27	2.26
Rocky Mountain	4.97	5.22	4.93	5.11	5.75	6.01	5.68	5.95
West Coast	0.39	0.39	0.39	0.39	0.44	0.44	0.44	0.45
Lower 48 Offshore								
Gulf	6.29	6.25	6.51	6.50	6.68	6.67	6.89	6.90
Pacific	0.06	0.06	0.19	0.19	0.07	0.07	0.20	0.20
Atlantic	0.00	0.00	0.03	0.03	0.00	0.00	0.14	0.14
Natural Gas Wellhead Prices (2000 dollars per thousand cubic feet)								
Lower 48 Average	3.07	3.04	3.04	3.02	3.26	3.20	3.22	3.15
Lower 48 Onshore								
Northeast	3.49	3.47	3.44	3.43	3.55	3.49	3.52	3.45
Gulf Coast	3.03	2.99	3.00	2.99	3.36	3.30	3.31	3.26
Midcontinent	3.08	3.07	3.06	3.02	3.30	3.26	3.26	3.23
Southwest	3.08	3.04	3.03	3.01	3.26	3.21	3.22	3.16
Rocky Mountain	2.91	2.81	2.84	2.82	3.00	2.94	2.96	2.86
West Coast	3.21	3.15	3.10	3.15	3.28	3.23	3.25	3.09
Lower 48 Offshore								
Gulf	3.10	3.11	3.06	3.06	3.26	3.20	3.22	3.16
Pacific	3.52	3.46	4.19	3.93	3.57	3.49	3.26	3.12
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Appendix C

Model Results:
Carbon Dioxide Emissions Limit Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000	Projections							
		2005		2010		2015		2020	
		Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit
Production									
Crude Oil and Lease Condensate	12.33	11.38	11.38	10.80	11.13	12.05	12.59	12.20	12.76
Natural Gas Plant Liquids	2.71	3.13	3.14	3.55	3.56	3.90	3.98	4.22	4.35
Dry Natural Gas	19.59	22.13	22.18	25.46	25.61	28.58	29.26	30.97	32.08
Coal	22.58	20.67	20.63	15.49	15.47	14.90	14.57	14.18	13.92
Nuclear Power	8.03	8.10	8.10	8.03	8.03	7.98	7.98	7.98	7.98
Renewable Energy[1]	6.46	7.84	7.84	9.35	9.34	12.00	11.91	14.27	14.09
Other[2]	1.10	0.66	0.66	0.37	0.37	0.75	0.89	0.42	0.85
Total	**72.80**	**73.91**	**73.92**	**73.06**	**73.51**	**80.16**	**81.19**	**84.24**	**86.03**
Imports									
Crude Oil[3]	19.69	22.28	22.28	24.37	24.03	23.75	23.29	24.45	23.97
Petroleum Products[4]	4.73	5.45	5.43	7.64	7.67	10.31	10.10	12.55	12.07
Natural Gas	3.85	5.01	4.99	6.67	6.63	7.18	6.85	7.45	7.00
Other Imports[5]	0.76	1.30	1.30	1.10	1.10	1.10	1.07	0.84	0.84
Total	**29.04**	**34.03**	**34.01**	**39.78**	**39.43**	**42.34**	**41.32**	**45.30**	**43.88**
Exports									
Petroleum[6]	2.15	1.68	1.68	1.88	1.89	2.03	2.05	2.13	2.15
Natural Gas	0.25	0.41	0.41	0.63	0.63	0.66	0.66	0.56	0.56
Coal	1.53	1.42	1.42	1.46	1.46	1.34	1.34	1.38	1.38
Total	**3.93**	**3.51**	**3.51**	**3.96**	**3.98**	**4.02**	**4.05**	**4.07**	**4.09**
Discrepancy[7]	**-1.37**	**0.05**	**0.05**	**0.18**	**0.13**	**0.30**	**0.09**	**-0.05**	**0.02**
Consumption									
Petroleum Products[8]	38.63	40.93	40.92	44.97	44.96	48.86	48.81	52.02	51.95
Natural Gas	23.43	27.00	27.03	31.21	31.30	34.85	35.20	37.57	38.23
Coal	22.34	19.52	19.49	14.16	14.22	13.53	13.54	13.01	12.88
Nuclear Power	8.03	8.10	8.10	8.03	8.03	7.98	7.98	7.98	7.98
Renewable Energy[1]	6.48	7.84	7.84	9.36	9.34	12.01	11.92	14.28	14.10
Other[9]	0.38	0.99	0.99	0.97	0.97	**0.93**	**0.91**	**0.65**	**0.65**
Total	**99.29**	**104.38**	**104.38**	**108.69**	**108.82**	**118.17**	**118.36**	**125.51**	**125.79**
Net Imports - Petroleum	**22.28**	**26.04**	**26.03**	**30.13**	**29.81**	**32.04**	**31.33**	**34.88**	**33.89**
Prices (2000 dollars per unit)									
World Oil Price (dollars per barrel)[10]	27.72	22.73	22.73	23.36	23.36	24.00	24.00	24.68	24.68
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.60	2.79	2.78	3.81	3.69	3.37	3.23	3.72	3.57
Coal Minemouth Price (dollars per ton)	16.45	15.58	15.59	13.79	13.85	13.23	13.32	12.54	12.61
Average Electricity Price (cents per kilowatthour)	6.9	8.6	8.6	9.1	9.0	8.5	8.5	8.3	8.2

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals and heat loss when natural gas is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
OCS = Outer continental shelf.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000). **Projections:** EIA, AEO2002 National Energy Modeling System runs CAPE2002.D111101A, ACCHDEM.D111101A.

Table C2. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2000	Projections 2005 Carbon Dioxide Emissions Limit	2005 Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	2010 Carbon Dioxide Emissions Limit	2010 Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	2015 Carbon Dioxide Emissions Limit	2015 Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	2020 Carbon Dioxide Emissions Limit	2020 Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit
Production									
Dry Gas Production[1]	19.08	21.55	21.59	24.79	24.93	27.83	28.49	30.16	31.23
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Net Imports	**3.52**	**4.50**	**4.48**	**5.90**	**5.86**	**6.37**	**6.05**	**6.73**	**6.28**
Canada	3.46	4.08	4.07	5.44	5.43	5.40	5.34	5.58	5.39
Mexico	-0.09	-0.22	-0.22	-0.42	-0.45	-0.29	-0.47	-0.20	-0.38
Liquefied Natural Gas	0.16	0.64	0.64	0.87	0.87	1.26	1.18	1.35	1.27
Total Supply	**22.69**	**26.16**	**26.19**	**30.81**	**30.90**	**34.31**	**34.66**	**37.00**	**37.63**
Consumption by Sector									
Residential	5.00	5.38	5.38	5.39	5.40	5.73	5.76	6.04	6.08
Commercial	3.27	3.68	3.68	3.91	3.92	4.57	4.60	5.20	5.23
Industrial[3]	8.41	8.88	8.88	9.07	9.10	9.93	10.07	10.35	10.53
Electric Generators[4]	4.24	6.23	6.25	9.51	9.52	10.86	10.93	11.92	12.20
Lease and Plant Fuel[5]	0.02	0.05	0.05	0.08	0.08	0.12	0.12	0.14	0.14
Pipeline Fuel	0.77	0.81	0.81	0.93	0.93	1.04	1.06	1.11	1.14
Transportation[6]	1.12	1.29	1.29	1.56	1.57	1.75	1.81	1.90	1.98
Total	**22.83**	**26.32**	**26.35**	**30.44**	**30.54**	**34.00**	**34.34**	**36.65**	**37.30**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**-0.14**	**-0.16**	**-0.16**	**0.36**	**0.37**	**0.31**	**0.32**	**0.35**	**0.33**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2000 values include net storage injections.
OCS = Outer continental shelf.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 transportation sector consumption: EIA, AEO2002 National Energy Modeling System run AEO2002D102001B. Other 2000 consumption: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System runs CAPE2002.D111101A, ACCHDEM.D111101A.

Table C3. Natural Gas Supply, Prices, Reserves, and Reserve Additions

Production Supply, Prices, and Reserves	2000	2005		2010		2015		2020	
		Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit
Lower 48 Average Wellhead Price[1]									
(2000 dollars per thousand cubic feet)	**3.60**	**2.79**	**2.78**	**3.81**	**3.69**	**3.37**	**3.23**	**3.72**	**3.57**
Dry Production (trillion cubic feet)[2]									
U.S. Total	**19.08**	**21.55**	**21.59**	**24.79**	**24.93**	**27.83**	**28.49**	**30.16**	**31.23**
Lower 48 Onshore	13.31	14.94	14.98	17.68	17.71	19.12	19.34	21.16	21.73
Associated-Dissolved[3]	1.79	1.63	1.63	1.45	1.44	1.40	1.39	1.39	1.38
Non-Associated	11.52	13.31	13.35	16.24	16.27	17.72	17.95	19.78	20.35
Conventional	6.89	7.27	7.27	8.51	8.28	9.40	9.26	10.49	10.55
Unconventional	4.63	6.03	6.08	7.72	7.99	8.32	8.69	9.29	9.80
Lower 48 Offshore	5.34	6.12	6.11	6.58	6.69	6.53	6.96	6.77	7.28
Associated-Dissolved[3]	1.16	1.19	1.19	1.22	1.24	1.29	1.35	1.26	1.32
Non-Associated	4.18	4.92	4.92	5.36	5.45	5.24	5.62	5.51	5.96
Alaska	0.43	0.50	0.50	0.53	0.53	2.19	2.19	2.22	2.22
Lower 48 End of Year Dry Reserves[2]									
(trillion cubic feet)	**162.31**	**166.38**	**167.50**	**173.57**	**179.42**	**185.93**	**194.76**	**195.63**	**204.00**
Supplemental Gas Supplies[4]	**0.10**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Lower 48 Wells (thousands)	**24.05**	**23.68**	**24.07**	**29.21**	**29.78**	**27.42**	**27.72**	**35.41**	**36.09**
Lower 48 Dry Natural Gas Reserves (trillion cubic feet)									
Lower 48 Total	162.3	166.4	167.5	173.6	179.4	185.9	194.8	195.6	204.0
Lower 48 Onshore	132.2	132.6	133.7	139.6	142.2	151.2	154.4	160.7	163.2
Associated-Dissolved[3]	15.0	13.7	13.7	12.2	12.1	11.7	11.7	11.6	11.6
Non-Associated	117.2	118.9	120.0	127.4	130.0	139.4	142.7	149.0	151.6
Conventional	64.0	60.4	60.4	59.4	60.0	64.2	65.3	66.9	68.2
Unconventional	53.1	58.5	59.6	68.0	70.0	75.2	77.5	82.2	83.5
Lower 48 Offshore	30.1	33.8	33.8	34.0	37.3	34.8	40.3	34.9	40.8
Associated-Dissolved[3]	7.0	7.2	7.2	7.3	7.4	7.7	8.1	7.6	7.9
Non-Associated	23.2	26.6	26.6	26.6	29.8	27.0	32.2	27.4	32.9
Lower 48 Dry Natural Gas Reserve Additions (trillion cubic feet)									
Lower 48 Total	22.5	22.5	22.8	26.6	27.6	26.8	27.7	29.6	30.4
Lower 48 Onshore	17.1	15.6	16.0	20.0	20.5	21.0	21.2	22.6	22.8
Associated-Dissolved[3]	1.2	1.1	1.1	1.3	1.3	1.3	1.3	1.4	1.4
Non-Associated	15.8	14.6	14.9	18.7	19.2	19.7	19.9	21.2	21.4
Conventional	9.6	6.9	6.9	8.8	8.8	10.6	10.6	10.5	10.5
Unconventional	6.2	7.7	8.1	10.0	10.5	9.1	9.3	10.6	10.9
Lower 48 Offshore	5.4	6.9	6.8	6.6	7.1	5.8	6.5	7.0	7.6
Associated-Dissolved[3]	1.0	1.2	1.2	1.2	1.3	1.4	1.5	1.1	1.2
Non-Associated	4.4	5.7	5.7	5.4	5.8	4.4	5.0	5.9	6.4

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[4]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
OCS = Outer continental shelf.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). 2000 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Other 2000 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System runs CAPE2002.D111101A, ACCHDEM.D111101A.

Table C4. Lower 48 Natural Gas Production and Wellhead Prices by Supply Region

Production and Prices	2000	Projections							
		2005		2010		2015		2020	
		Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Rocky Mountain and OCS Access with Carbon Dioxide Emissions Limit
Dry Production (trillion cubic feet)[1]									
Lower 48 Total	18.65	21.06	21.10	24.26	24.40	25.64	26.31	27.94	29.01
Lower 48 Onshore									
Northeast	0.93	1.18	1.18	1.65	1.67	1.94	2.00	2.29	2.36
Gulf Coast	4.81	5.28	5.27	5.90	5.70	6.51	6.36	6.61	6.59
Midcontinent	2.58	3.00	2.99	3.31	3.25	3.35	3.31	3.74	3.78
Southwest	1.61	1.60	1.60	2.08	2.05	2.22	2.20	2.36	2.34
Rocky Mountain	3.08	3.56	3.60	4.38	4.68	4.70	5.09	5.72	6.21
West Coast	0.31	0.33	0.33	0.36	0.36	0.39	0.39	0.45	0.45
Lower 48 Offshore									
Gulf	5.28	6.06	6.06	6.52	6.51	6.47	6.62	6.70	6.91
Pacific	0.06	0.06	0.06	0.06	0.11	0.06	0.18	0.07	0.21
Atlantic	0.00	0.00	0.00	0.00	0.07	0.00	0.16	0.00	0.16
Natural Gas Wellhead Prices (2000 dollars per thousand cubic feet)									
Lower 48 Average	3.60	2.79	2.78	3.81	3.69	3.37	3.23	3.72	3.57
Lower 48 Onshore									
Northeast	4.17	3.08	3.07	4.10	4.02	3.90	3.78	4.05	3.94
Gulf Coast	3.74	2.83	2.82	3.82	3.73	3.48	3.36	3.93	3.77
Midcontinent	3.56	2.86	2.86	3.94	3.85	3.42	3.30	3.85	3.64
Southwest	3.71	2.76	2.76	3.64	3.59	3.43	3.29	3.76	3.62
Rocky Mountain	3.26	2.64	2.61	3.43	3.25	2.86	2.71	3.31	3.14
West Coast	3.76	3.04	3.02	3.51	3.35	2.61	2.63	3.70	3.58
Lower 48 Offshore									
Gulf	3.54	2.74	2.73	3.97	3.90	3.46	3.32	3.65	3.58
Pacific	4.26	2.89	2.87	3.82	1.33	2.83	3.15	4.02	3.37
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[1]Marketed production (wet) minus extraction losses.
OCS = Outer continental shelf.
Note: Supply regions are defined in *Documentation of the Oil and Gas Supply Module*, Energy Information Administration (EIA), DOE/EIA-M063(2000) (Washington, DC, January 2000). Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Projections: EIA, AEO2002 National Energy Modeling System runs CAPE2002.D111101A, ACCHDEM.D111101A.

Table C5. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000	Projections 2005 Carbon Dioxide Emissions Limit	2005 Low LNG Costs with Carbon Dioxide Emissions Limit	2005 High LNG Costs with Carbon Dioxide Emissions Limit	2010 Carbon Dioxide Emissions Limit	2010 Low LNG Costs with Carbon Dioxide Emissions Limit	2010 High LNG Costs with Carbon Dioxide Emissions Limit
Production							
Crude Oil and Lease Condensate	12.33	11.38	11.38	11.38	10.80	10.80	10.80
Natural Gas Plant Liquids	2.71	3.13	3.14	3.14	3.55	3.52	3.53
Dry Natural Gas	19.59	22.13	22.14	22.16	25.46	25.18	25.27
Coal	22.58	20.67	20.66	20.65	15.49	15.51	15.51
Nuclear Power	8.03	8.10	8.10	8.10	8.03	8.03	8.03
Renewable Energy[1]	6.46	7.84	7.83	7.84	9.35	9.32	9.36
Other[2]	1.10	0.66	0.66	0.65	0.37	0.37	0.37
Total	**72.80**	**73.91**	**73.91**	**73.92**	**73.06**	**72.73**	**72.87**
Imports							
Crude Oil[3]	19.69	22.28	22.28	22.28	24.37	24.38	24.38
Petroleum Products[4]	4.73	5.45	5.44	5.44	7.64	7.69	7.69
Natural Gas	3.85	5.01	5.01	5.01	6.67	6.81	6.61
Other Imports[5]	0.76	1.30	1.30	1.30	1.10	1.10	1.10
Total	**29.04**	**34.03**	**34.03**	**34.04**	**39.78**	**39.98**	**39.78**
Exports							
Petroleum[6]	2.15	1.68	1.68	1.68	1.88	1.88	1.87
Natural Gas	0.25	0.41	0.41	0.41	0.63	0.63	0.63
Coal	1.53	1.42	1.42	1.42	1.46	1.46	1.46
Total	**3.93**	**3.51**	**3.51**	**3.51**	**3.96**	**3.97**	**3.96**
Discrepancy[7]	**-1.37**	**0.05**	**0.05**	**0.06**	**0.18**	**0.13**	**0.02**
Consumption							
Petroleum Products[8]	38.63	40.93	40.92	40.93	44.97	45.00	45.01
Natural Gas	23.43	27.00	27.01	27.03	31.21	31.07	30.94
Coal	22.34	19.52	19.52	19.50	14.16	14.22	14.35
Nuclear Power	8.03	8.10	8.10	8.10	8.03	8.03	8.03
Renewable Energy[1]	6.48	7.84	7.84	7.84	9.36	9.33	9.37
Other[9]	0.38	0.99	0.99	0.99	0.97	0.97	0.97
Total	**99.29**	**104.38**	**104.38**	**104.39**	**108.69**	**108.61**	**108.67**
Net Imports - Petroleum	**22.28**	**26.04**	**26.04**	**26.04**	**30.13**	**30.19**	**30.20**
Prices (2000 dollars per unit)							
World Oil Price (dollars per barrel)[10]	27.72	22.73	22.73	22.73	23.36	23.36	23.36
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.60	2.79	2.79	2.79	3.81	3.81	3.86
Coal Minemouth Price (dollars per ton)	16.45	15.58	15.57	15.55	13.79	13.85	13.89
Average Electricity Price (cents per kilowatthour)	6.9	8.6	8.6	8.6	9.1	9.1	9.1

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals and heat loss when natural gas is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
LNG = Liquefied natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 petroleum values: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). Other 2000 values: EIA, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/4Q) (Washington, DC, October-December 2000). **Projections:** EIA, AEO2002 National Energy Modeling System runs CAPE2002.D111101A, LCSTHDEM.D111201B, HCSTHDEM.D111201A.

Supply, Disposition, and Prices	Projections					
	2015			2020		
	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit
Production						
Crude Oil and Lease Condensate . .	12.05	12.05	12.07	12.20	12.32	12.24
Natural Gas Plant Liquids	3.90	3.86	3.93	4.22	4.19	4.22
Dry Natural Gas	28.58	28.30	28.81	30.97	30.80	31.02
Coal	14.90	14.75	14.78	14.18	14.34	14.32
Nuclear Power	7.98	7.98	7.98	7.98	7.98	7.98
Renewable Energy[1]	12.00	11.94	11.93	14.27	14.16	14.23
Other[2]	0.75	0.87	0.49	0.42	0.47	0.42
Total	**80.16**	**79.75**	**79.98**	**84.24**	**84.28**	**84.44**
Imports						
Crude Oil[3]	23.75	23.75	23.74	24.45	24.35	24.43
Petroleum Products[4]	10.31	10.22	10.49	12.55	12.51	12.57
Natural Gas	7.18	7.51	6.77	7.45	7.77	7.03
Other Imports[5]	1.10	1.10	1.11	0.84	0.85	0.86
Total	**42.34**	**42.58**	**42.12**	**45.30**	**45.47**	**44.88**
Exports						
Petroleum[6]	2.03	2.03	2.03	2.13	2.13	2.12
Natural Gas	0.66	0.66	0.66	0.56	0.56	0.56
Coal	1.34	1.34	1.34	1.38	1.38	1.38
Total	**4.02**	**4.03**	**4.03**	**4.07**	**4.08**	**4.07**
Discrepancy[7]	**0.30**	**0.17**	**0.10**	**-0.05**	**0.37**	**-0.22**
Consumption						
Petroleum Products[8]	48.86	48.79	48.92	52.02	51.99	52.05
Natural Gas	34.85	34.95	34.65	37.57	37.77	37.18
Coal	13.53	13.53	13.53	13.01	12.72	13.34
Nuclear Power	7.98	7.98	7.98	7.98	7.98	7.98
Renewable Energy[1]	12.01	11.95	11.94	14.28	14.17	14.24
Other[9]	0.93	0.94	0.95	0.65	0.66	0.67
Total	**118.17**	**118.14**	**117.96**	**125.51**	**125.30**	**125.47**
Net Imports - Petroleum	**32.04**	**31.94**	**32.20**	**34.88**	**34.72**	**34.87**
Prices (2000 dollars per unit)						
World Oil Price (dollars per barrel)[10] . .	24.00	24.00	24.00	24.68	24.68	24.68
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11] . .	3.37	3.33	3.50	3.72	3.63	3.79
Coal Minemouth Price (dollars per ton)	13.23	13.27	13.33	12.54	12.49	12.55
Average Electricity Price (cents per kilowatthour)	8.5	8.6	8.7	8.3	8.3	8.4

Table C6. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2000	Projections 2005 Carbon Dioxide Emissions Limit	2005 Low LNG Costs with Carbon Dloxide Emissions Limit	2005 High LNG Costs with Carbon Dioxide Emissions Limit	2010 Carbon Dloxide Emissions Limit	2010 Low LNG Costs with Carbon Dioxide Emissions Limit	2010 High LNG Costs with Carbon Doxide Emissions Limit
Production							
Dry Gas Production[1]	19.08	21.55	21.56	21.58	24.79	24.52	24.61
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.11	0.11	0.11	0.11
Net Imports	**3.52**	**4.50**	**4.50**	**4.50**	**5.90**	**6.03**	**5.84**
Canada	3.46	4.08	4.08	4.08	5.44	5.43	5.43
Mexico	-0.09	-0.22	-0.22	-0.22	-0.42	-0.42	-0.42
Liquefied Natural Gas	0.16	0.64	0.64	0.64	0.87	1.02	0.83
Total Supply	**22.69**	**26.16**	**26.17**	**26.19**	**30.81**	**30.67**	**30.56**
Consumption by Sector							
Residential	5.00	5.38	5.38	5.38	5.39	5.38	5.38
Commercial	3.27	3.68	3.68	3.68	3.91	3.91	3.91
Industrial[3]	8.41	8.88	8.88	8.88	9.07	9.03	9.02
Electric Generators[4]	4.24	6.23	6.24	6.27	9.51	9.44	9.32
Lease and Plant Fuel[5]	0.02	0.05	0.05	0.05	0.08	0.08	0.08
Pipeline Fuel	0.77	0.81	0.81	0.81	0.93	0.91	0.92
Transportation[6]	1.12	1.29	1.29	1.29	1.56	1.54	1.55
Total	**22.83**	**26.32**	**26.33**	**26.35**	**30.44**	**30.31**	**30.18**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**-0.14**	**-0.16**	**-0.16**	**-0.16**	**0.36**	**0.36**	**0.38**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2000 values include net storage injections.
LNG = Liquefied natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). 2000 transportation sector consumption: EIA, AEO2002 National Energy Modeling System run AEO2002D102001B. Other 2000 consumption: EIA, *Short-Term Energy Outlook, October 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/oct01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2002 National Energy Modeling System run AEO2002.D102001B. **Projections:** EIA, AEO2002 National Energy Modeling System runs CAPE2002.D111101A, LCSTHDEM.D111201B, HCSTHDEM.D111201A.

Supply and Disposition	Projections					
	2015			2020		
	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit
Production						
Dry Gas Production[1]	27.83	27.55	28.05	30.16	29.99	30.20
Supplemental Natural Gas[2] . . .	0.11	0.11	0.11	0.11	0.11	0.11
Net Imports	**6.37**	**6.70**	**5.97**	**6.73**	**7.04**	**6.32**
Canada	5.40	5.41	5.44	5.58	5.50	5.69
Mexico	-0.29	-0.29	-0.29	-0.20	-0.20	-0.20
Liquefied Natural Gas	1.26	1.58	0.83	1.35	1.74	0.83
Total Supply	**34.31**	**34.36**	**34.14**	**37.00**	**37.15**	**36.63**
Consumption by Sector						
Residential	5.73	5.74	5.71	6.04	6.07	6.02
Commercial	4.57	4.59	4.58	5.20	5.24	5.22
Industrial[3]	9.93	10.06	9.84	10.35	10.42	10.33
Electric Generators[4]	10.86	10.82	10.74	11.92	11.99	11.54
Lease and Plant Fuel[5]	0.12	0.11	0.11	0.14	0.14	0.13
Pipeline Fuel	1.04	1.03	1.05	1.11	1.10	1.12
Transportation[6]	1.75	1.74	1.77	1.90	1.90	1.91
Total	**34.00**	**34.09**	**33.80**	**36.65**	**36.85**	**36.27**
Natural Gas to Liquids	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Discrepancy[7]	**0.31**	**0.27**	**0.34**	**0.35**	**0.30**	**0.36**

Table C7. Natural Gas Supply, Prices, Reserves, and Reserve Additions

Production Supply, Prices, and Reserves	2000	Projections					
		2005			2010		
		Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit
Lower 48 Average Wellhead Price[1]							
(2000 dollars per thousand cubic feet)	**3.60**	**2.79**	**2.79**	**2.79**	**3.81**	**3.81**	**3.86**
Dry Production (trillion cubic feet)[2]							
U.S. Total	**19.08**	**21.55**	**21.56**	**21.58**	**24.79**	**24.52**	**24.61**
Lower 48 Onshore	13.31	14.94	14.95	14.96	17.68	17.54	17.50
Associated-Dissolved[3]	1.79	1.63	1.63	1.63	1.45	1.45	1.45
Non-Associated	11.52	13.31	13.31	13.33	16.24	16.09	16.05
Conventional	6.89	7.27	7.28	7.28	8.51	8.42	8.36
Unconventional	4.63	6.03	6.04	6.04	7.72	7.67	7.69
Lower 48 Offshore	5.34	6.12	6.12	6.13	6.58	6.45	6.58
Associated-Dissolved[3]	1.16	1.19	1.19	1.19	1.22	1.22	1.22
Non-Associated	4.18	4.92	4.93	4.93	5.36	5.23	5.36
Alaska	0.43	0.50	0.50	0.50	0.53	0.53	0.53
Lower 48 End of Year Dry Reserves[2]							
(trillion cubic feet)	**162.31**	**166.38**	**166.36**	**166.35**	**173.57**	**174.04**	**174.05**
Supplemental Gas Supplies[4]	**0.10**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Lower 48 Wells (thousands)	**24.05**	**23.68**	**23.66**	**23.69**	**29.21**	**29.18**	**29.45**
Lower 48 Dry Natural Gas Reserves							
(trillion cubic feet)							
Lower 48 Total	162.3	166.4	166.4	166.3	173.6	174.0	174.1
Lower 48 Onshore	132.2	132.6	132.6	132.6	139.6	140.0	140.2
Associated-Dissolved[3]	15.0	13.7	13.7	13.7	12.2	12.2	12.2
Non-Associated	117.2	118.9	118.9	118.9	127.4	127.9	128.0
Conventional	64.0	60.4	60.4	60.4	59.4	59.9	60.0
Unconventional	53.1	58.5	58.4	58.5	68.0	68.0	68.1
Lower 48 Offshore	30.1	33.8	33.8	33.8	34.0	34.0	33.9
Associated-Dissolved[3]	7.0	7.2	7.2	7.2	7.3	7.3	7.3
Non-Associated	23.2	26.6	26.6	26.6	26.6	26.7	26.5
Lower 48 Dry Natural Gas Reserve Additions							
(trillion cubic feet)							
Lower 48 Total	22.5	22.5	22.5	22.5	26.6	26.5	26.6
Lower 48 Onshore	17.1	15.6	15.6	15.6	20.0	19.9	20.1
Associated-Dissolved[3]	1.2	1.1	1.1	1.1	1.3	1.3	1.3
Non-Associated	15.8	14.6	14.6	14.6	18.7	18.7	18.8
Conventional	9.6	6.9	6.9	6.9	8.8	8.8	8.8
Unconventional	6.2	7.7	7.7	7.7	10.0	9.9	10.0
Lower 48 Offshore	5.4	6.9	6.9	6.9	6.6	6.6	6.6
Associated-Dissolved[3]	1.0	1.2	1.2	1.2	1.2	1.2	1.2
Non-Associated	4.4	5.7	5.7	5.7	5.4	5.4	5.4

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[4]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
LNG = Liquefied natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000/1) (Washington, DC, June 2001). 2000 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Other 2000 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2002 National Energy Modeling System runs CAPE2002.D111101A, LCSTHDEM.D111201B, HCSTHDEM.D111201A.

Production Supply, Prices, and Reserves	Projections					
	2015			2020		
	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit
Lower 48 Average Wellhead Price[1]						
(2000 dollars per thousand cubic feet)	**3.37**	**3.33**	**3.50**	**3.72**	**3.63**	**3.79**
Dry Production (trillion cubic feet)[2]						
U.S. Total	**27.83**	**27.55**	**28.05**	**30.16**	**29.99**	**30.20**
Lower 48 Onshore	19.12	18.93	19.27	21.16	21.12	21.16
Associated-Dissolved[3]	1.40	1.40	1.40	1.39	1.38	1.39
Non-Associated	17.72	17.53	17.87	19.78	19.73	19.77
Conventional	9.40	9.26	9.44	10.49	10.42	10.41
Unconventional	8.32	8.27	8.43	9.29	9.32	9.36
Lower 48 Offshore	6.53	6.44	6.59	6.77	6.66	6.82
Associated-Dissolved[3]	1.29	1.29	1.29	1.26	1.27	1.27
Non-Associated	5.24	5.15	5.30	5.51	5.39	5.56
Alaska	2.19	2.19	2.19	2.22	2.22	2.22
Lower 48 End of Year Dry Reserves[2]						
(trillion cubic feet)	**185.93**	**187.04**	**186.33**	**195.63**	**197.07**	**197.76**
Supplemental Gas Supplies[4]	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Total Lower 48 Wells (thousands)	**27.42**	**27.36**	**27.96**	**35.41**	**34.83**	**36.27**
Lower 48 Dry Natural Gas Reserves						
(trillion cubic feet)						
Lower 48 Total	185.9	187.0	186.3	195.6	197.1	197.8
Lower 48 Onshore	151.2	152.3	151.7	160.7	161.5	162.5
Associated-Dissolved[3]	11.7	11.8	11.8	11.6	11.6	11.7
Non-Associated	139.4	140.5	140.0	149.0	149.8	150.8
Conventional	64.2	65.3	64.7	66.9	68.2	67.6
Unconventional	75.2	75.2	75.3	82.2	81.6	83.2
Lower 48 Offshore	34.8	34.8	34.6	34.9	35.6	35.2
Associated-Dissolved[3]	7.7	7.7	7.7	7.6	7.6	7.6
Non-Associated	27.0	27.0	26.9	27.4	28.0	27.7
Lower 48 Dry Natural Gas Reserve Additions						
(trillion cubic feet)						
Lower 48 Total	26.8	26.8	26.9	29.6	29.4	30.0
Lower 48 Onshore	21.0	21.0	21.2	22.6	22.3	22.9
Associated-Dissolved[3]	1.3	1.3	1.4	1.4	1.4	1.4
Non-Associated	19.7	19.7	19.9	21.2	21.0	21.5
Conventional	10.6	10.6	10.7	10.5	10.5	10.5
Unconventional	9.1	9.1	9.2	10.6	10.4	10.9
Lower 48 Offshore	5.8	5.7	5.7	7.0	7.0	7.2
Associated-Dissolved[3]	1.4	1.4	1.4	1.1	1.1	1.1
Non-Associated	4.4	4.3	4.3	5.9	5.9	6.0

Table C8. Lower 48 Natural Gas Production and Wellhead Prices by Supply Region

Production and Prices	2000	Projections					
		2005			2010		
		Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit
Dry Production (trillion cubic feet)[1]							
Lower 48 Total	18.65	21.06	21.07	21.08	24.26	23.99	24.08
Lower 48 Onshore							
Northeast	0.93	1.18	1.18	1.18	1.65	1.63	1.64
Gulf Coast	4.81	5.28	5.28	5.29	5.90	5.82	5.74
Midcontinent	2.58	3.00	3.00	3.00	3.31	3.34	3.32
Southwest	1.61	1.60	1.60	1.60	2.08	2.03	2.07
Rocky Mountain	3.08	3.56	3.56	3.56	4.38	4.35	4.36
West Coast	0.31	0.33	0.33	0.33	0.36	0.36	0.36
Lower 48 Offshore							
Gulf	5.28	6.06	6.06	6.07	6.52	6.40	6.52
Pacific	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas Wellhead Prices (2000 dollars per thousand cubic feet)							
Lower 48 Average	3.60	2.79	2.79	2.79	3.81	3.81	3.86
Lower 48 Onshore							
Northeast	4.17	3.08	3.08	3.09	4.10	4.10	4.15
Gulf Coast	3.74	2.83	2.83	2.83	3.82	3.80	3.79
Midcontinent	3.56	2.86	2.86	2.87	3.94	4.02	3.87
Southwest	3.71	2.76	2.76	2.77	3.64	3.58	3.70
Rocky Mountain	3.26	2.64	2.64	2.65	3.43	3.43	3.47
West Coast	3.76	3.04	3.03	3.04	3.51	3.50	3.49
Lower 48 Offshore							
Gulf	3.54	2.74	2.74	2.74	3.97	3.99	4.17
Pacific	4.26	2.89	2.88	2.89	3.82	3.89	3.95
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[1]Marketed production (wet) minus extraction losses.
LNG = Liquefied natural gas.
Note: Supply regions are defined in *Documentation of the Oil and Gas Supply Module*, Energy Information Administration (EIA), DOE/EIA-M063(2000) (Washington, DC, January 2000). Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (Washington, DC, June 2001). Projections: EIA, AEO2002 National Energy Modeling System runs CAPE2002.D111101A, LCSTHDEM.D111201B, HCSTHDEM.D111201A.

Production and Prices	Projections					
	2015			2020		
	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit	Carbon Dioxide Emissions Limit	Low LNG Costs with Carbon Dioxide Emissions Limit	High LNG Costs with Carbon Dioxide Emissions Limit
Dry Production (trillion cubic feet)[1]						
Lower 48 Total	25.64	25.36	25.86	27.94	27.77	27.98
Lower 48 Onshore						
Northeast	1.94	1.93	1.98	2.29	2.27	2.31
Gulf Coast	6.51	6.38	6.48	6.61	6.53	6.48
Midcontinent	3.35	3.32	3.43	3.74	3.73	3.78
Southwest	2.22	2.22	2.24	2.36	2.35	2.39
Rocky Mountain	4.70	4.68	4.76	5.72	5.79	5.76
West Coast	0.39	0.39	0.39	0.45	0.44	0.45
Lower 48 Offshore						
Gulf	6.47	6.38	6.53	6.70	6.59	6.75
Pacific	0.06	0.06	0.06	0.07	0.07	0.07
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas Wellhead Prices (2000 dollars per thousand cubic feet)						
Lower 48 Average	3.37	3.33	3.50	3.72	3.63	3.79
Lower 48 Onshore						
Northeast	3.90	3.81	4.06	4.05	3.99	4.11
Gulf Coast	3.48	3.42	3.63	3.93	3.83	3.98
Midcontinent	3.42	3.39	3.57	3.85	3.71	3.96
Southwest	3.43	3.33	3.53	3.76	3.69	3.88
Rocky Mountain	2.86	2.85	2.98	3.31	3.19	3.38
West Coast	2.61	2.59	2.59	3.70	3.65	3.86
Lower 48 Offshore						
Gulf	3.46	3.47	3.60	3.65	3.62	3.72
Pacific	2.83	2.81	2.80	4.02	3.98	4.18
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00