The Natural Gas Industry and Markets in 2002

This special report provides an overview of the supply and disposition of natural gas in 2002 and is intended as a supplement to the Energy Information Administration's (EIA) *Natural Gas Annual 2002* (*NGA*). Unless otherwise stated, all data in this report are based on summary statistics published in the *NGA* 2002. Questions or comments on the contents of this report should be directed to William Trapmann at william.trapmann@eia.doe.gov or (202) 586-6408.

Overview

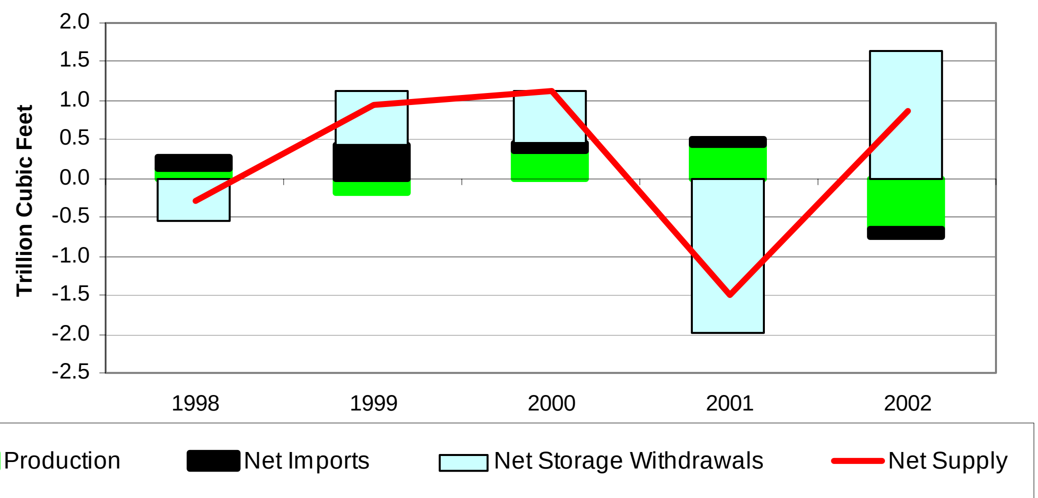
The natural gas industry and markets experienced a number of key changes during 2002. Current supplies of production and net imports decreased by about 750 billion cubic feet (Bcf) in 2002, so storage stocks were drawn down to meet an increase in consumption. Average prices in 2002 declined from the relatively high levels of 2001. The average wellhead price was $2.95 per thousand cubic feet (Mcf)—a decline of more than $1 from the previous year. Prices for imported gas also were lower. The lower prices for gas supplies led to decreases in prices of gas delivered to all consuming sectors. The average price for delivered gas to each sector fell by 18 percent or more. In response to the lower prices, natural gas consumption by each end-use sector increased, following an overall decline in consumption in 2001.

Natural Gas Supply

Natural Gas Production and Net Imports Declined in 2002

Natural gas supplies (dry production, net imports, net storage withdrawals, and supplemental volumes) were 860 Bcf higher in 2002 compared with 2001 levels, driven mainly by an increased drawdown from storage (Figure 1). Domestic production fell by about 650 Bcf in 2002 compared with 2001 levels, after growing by almost 800 Bcf in the previous 2 years combined. The downturn in domestic production reflects the falloff in drilling for gas prospects from the record level of 2001. Domestic net storage withdrawals in 2002 were about 470 Bcf, compared with net injections in 2001 that exceeded 1,100 Bcf, resulting in a swing in net supply from storage of slightly more than 1,600 Bcf between years. Net imports fell by slightly more than 100 Bcf, although gross imports were up by roughly 40 Bcf. This increment was more than offset by a larger increase in gas exports, which resulted in the first decline in net imports since 1986.

Figure 1. U.S. Natural Gas Supply—Differences Between Years, 1998-2002



Some additional highlights related to the supply data follow.

Natural Gas Production Fell in 2002, Reversing a 2-Year Trend

- **The United States had almost 20.0 trillion cubic feet (Tcf) of marketed natural gas production in 2002, which is 3 percent less than in 2001** and the lowest level since 1999 when marketed production reached 19.8 Tcf (Figure 2). This 3-percent decrease from the 2001 level is the largest year-to-year decrease in marketed production in the past 5 years. Moreover, marketed production was nearly 277 Bcf or over 1 percent less than the level reported in 2000.

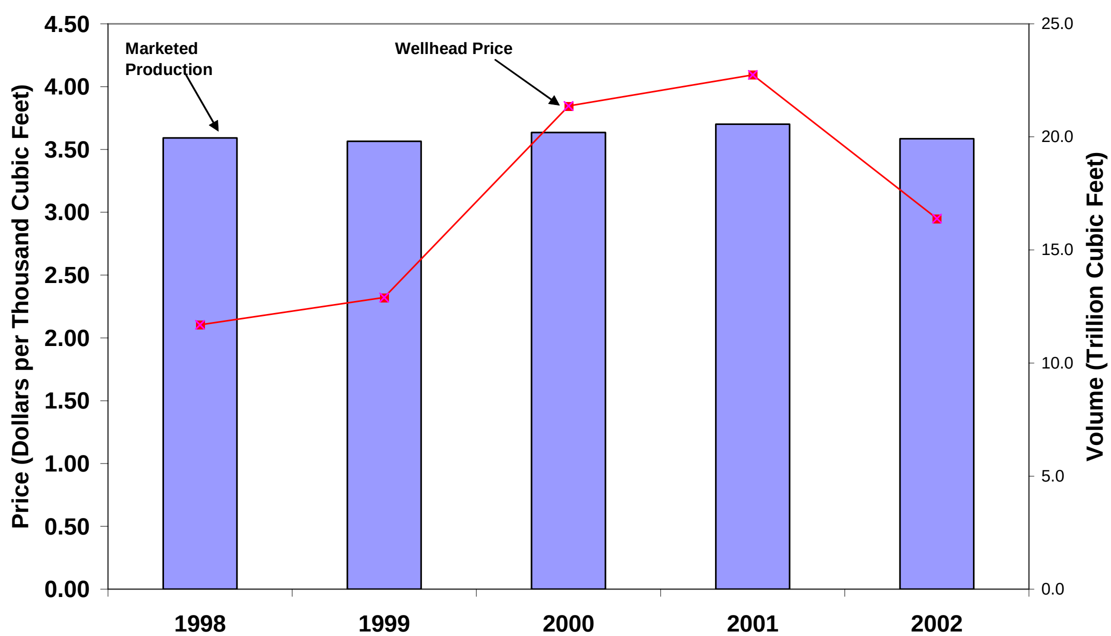
- **Marketed natural gas production from State and Federal waters was roughly 5.2 Tcf in 2002, almost 11 percent less than in 2001.** Offshore fields accounted for roughly 26 percent of total marketed production in the United States in 2002, down from 28 percent in 2001.

- **Texas, New Mexico, Oklahoma, Wyoming, and Louisiana (including Federal offshore production) continue to account for nearly 80 percent of marketed production.** Marketed production declined 877 Bcf or 6 percent in Texas, New Mexico, Oklahoma, Louisiana, and the Gulf of Mexico in 2002. However, these declines were partially offset by increases in Colorado and Wyoming of 114 Bcf, or 5 percent. This may reflect the growing prominence of the Rocky Mountains region in natural gas production, highlighting a shift from conventional gas fields to unconventional gas fields such as tight sands, shales, and coalbeds.

- **The national average natural gas wellhead price was $2.95 per Mcf in 2002, which was 26 percent less than in 2001.** In 2002, the Ohio price was the highest in the Lower 48 States at $4.52 per Mcf, and Nebraska had the lowest average wellhead price of $1.52 per Mcf.

- **Measured in constant 2002 dollars, the average wellhead price was the lowest in 3 years but was the third-highest wellhead price since 1985** when it averaged $3.77 per Mcf.

Figure 2. U.S. Average Wellhead Prices and Marketed Production, 1998-2002



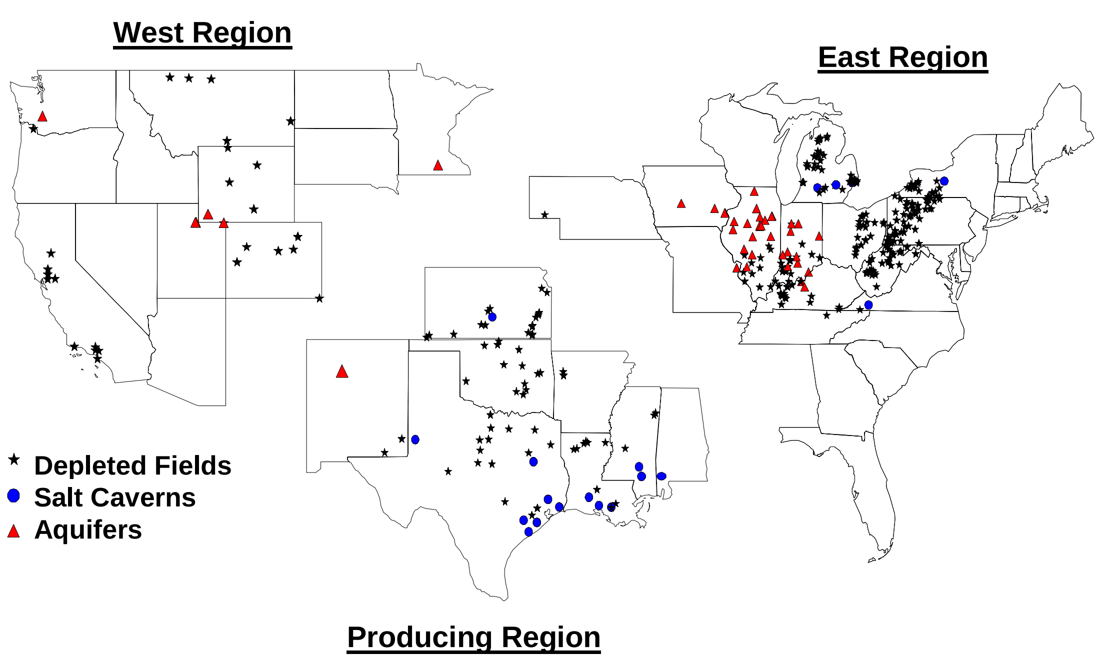
Note: Prices in 2002 dollars.

Underground Natural Gas Storage Fields Generally Are Located in Former or Current Production Areas

- **Total underground natural gas storage capacity measured 8,207 Bcf in 2002, with more than 41 percent of the capacity clustered in four States.** Although storage facilities are present in 30 of the Lower 48 States, their distribution patterns reflect varying geographic advantages. The largest share of underground storage, measured by total storage capacity, occurs in Michigan, where 12.6 percent of all storage is located, followed by Illinois with 11.5 percent. There is a virtual tie for third place between Pennsylvania and Texas at 8.7 and 8.5 percent, respectively. In terms of number of fields, three States account for roughly one-third of all facilities: Pennsylvania (57), Michigan (45), and Texas (35) comprise 137 of the 407 locations. There are three major types of underground storage: depleted fields, aquifers, and salt formations. The dominant type is the depleted fields category, which accounts for 82 percent of capacity. Aquifers at 15 percent and salt formations at 3 percent account for the remainder of capacity. The aquifer and salt formation fields are considerably more concentrated than depleted fields. Illinois (17) and Indiana (8) contain 66 percent of all aquifer fields. Salt formations are primarily located in Texas (14) and Louisiana (6), which hold 69 percent of those fields (Figure 3).

- **Working gas inventories in underground storage began 2002 at 2,904 Bcf, which is the highest level since 1990, but ended the year 35 Bcf, or 1.5 percent, below the previous 5-year average (1997-2001).** Natural gas in storage at the beginning of 2002 was at the highest level since 1990, having benefited especially from moderate temperatures in November and December 2001. The unusually mild temperatures continued through February 2002. Although March was slightly colder than normal, working gas stocks at the end of the winter (March 31) were the highest they had been in 10 years. Despite only a moderate refill volume of 1,598 Bcf from April through October, stocks were above the 5-year average as winter 2002-2003 began. However, colder-than-normal temperatures in November began a period of above average withdrawals at the end of 2002. Working gas stocks by month in 2002 exceeded the previous 5-year average (1997-2001) in every month except December.[i]

Figure 3. Underground Natural Gas Storage Facilities in the Lower 48 States



- **Net withdrawals from underground storage were unusually high in December 2002 as prices surged.** The wellhead price during the 2002 refill season (April through October) averaged $2.99 per Mcf. As prices rose in the latter portion of the calendar year to $3.59 per Mcf in November and $3.84 in December 2002, there was an economic incentive to withdraw gas from storage. This tendency was exacerbated by colder-than-normal temperatures in November and December. Consequently, the working gas in storage at the end of December 2002 was below the level of December 2001 by roughly 500 Bcf.

- **As of December 31, 2002, liquefied natural gas (LNG) storage facilities, which are generally operated by local utilities and interstate pipeline companies to meet peak demand periods, had the gaseous equivalent of approximately 66 Bcf in storage.** This total does not include LNG inventory held by marine terminals during the processing of imports and exports. During the year, approximately 43 Bcf was withdrawn, while 42 Bcf was added to storage resulting in a net decline of 1 Bcf for 2002. The LNG storage inventory accounts for a small portion of total U.S. working gas in storage. At the end of 2002, LNG stocks were the equivalent of 2.7 percent of the 2,375 Bcf held in underground storage facilities. Massachusetts was the State with the largest LNG inventory in storage as of December 31, 2002, at approximately 11.5 Bcf. North Carolina had the second largest inventory at about 7.3 Bcf. EIA estimates that the total capacity of LNG storage facilities at the end of 2002 (excluding marine facility storage) was 86 Bcf, with nearly 82 percent of the total in the East Region.[ii]

Although Imports Increased, Natural Gas Exports Grew by an Even Larger Amount

- **Net imports of natural gas into the United States declined by 104 Bcf to 3,499 Bcf in 2002**, owing to slower growth in pipeline imports from Canada and increasing U.S. exports, particularly to Mexico. Net imports were about 3 percent lower in 2002 than in 2001. This is the first decline since 1986. Contributing to the decline in net imports, LNG imports fell by 9 Bcf after increasing 153 Bcf over the previous 3 years. While gross imports grew 1 percent to 4,015 Bcf (Figure 4), gross exports grew 38 percent to 516 Bcf. Mexican pipeline exports jumped 87 percent to 263 Bcf.

- **Imports of natural gas from Canada rose for the 16th consecutive year**. However, the growth of Canadian gas imports slowed in 2002. Canadian imports increased to 3,785 Tcf, which was 56 Bcf higher than in 2001. The slowed growth–1.5 percent versus about 6.9 percent in the previous 3 years–was likely due in part to lower Canadian drilling activity than in 2001 as reduced Canadian domestic and import prices provided less incentive to producers. The United States exported 22.6 Bcf, or 14 percent, more gas to Canada for a total of 189 Bcf in 2002. As a result, net imports of Canadian gas grew by less than 1 percent.

Figure 4. Natural Gas Imports to the United States, 1987-2002

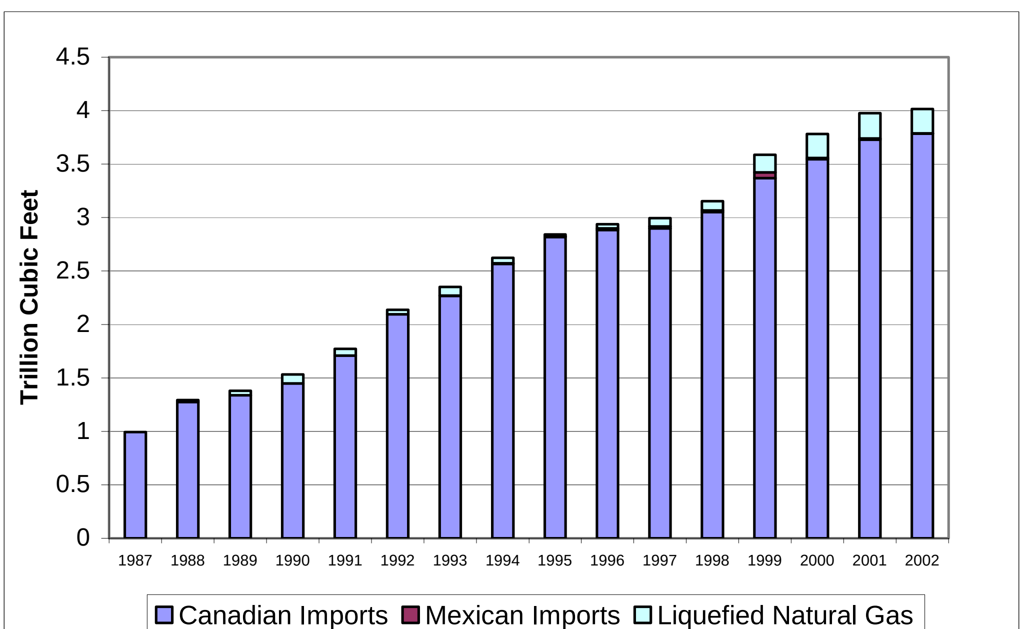
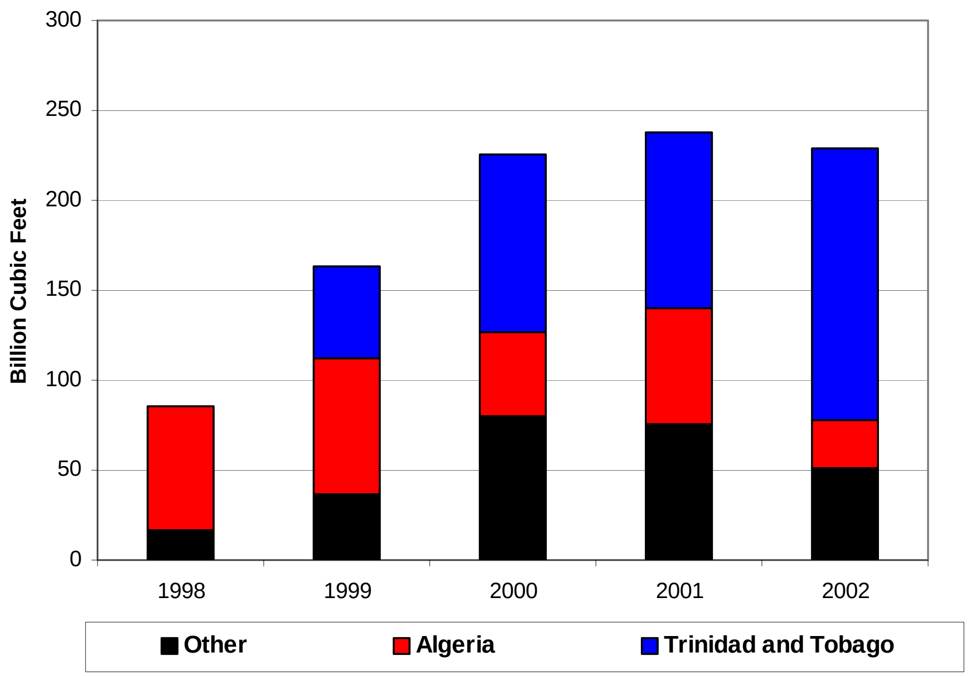


Figure 5. LNG Imports by Country of Origin



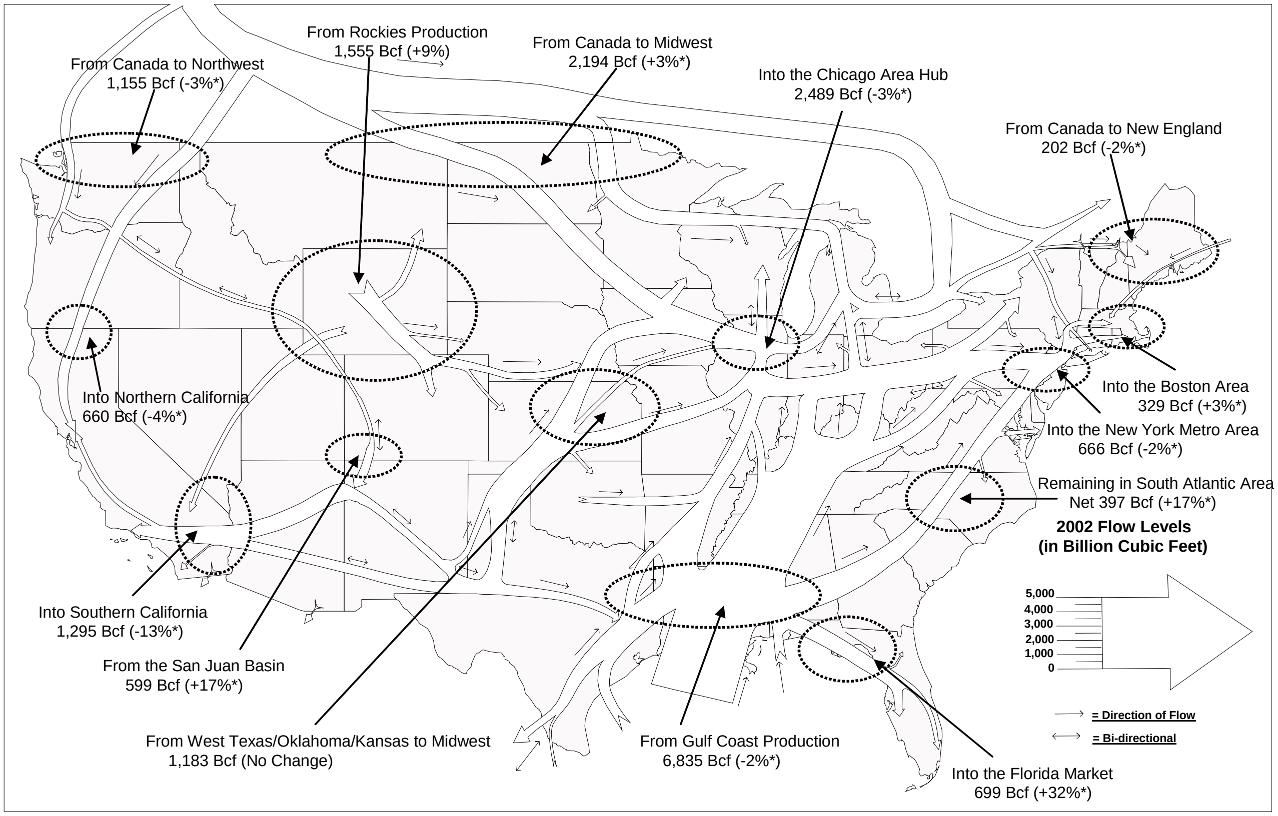
- **LNG imports have grown significantly over the past couple of years from the levels of the 1990s**, although they still accounted for only about 1 percent of total supply in 2002. LNG imports during 2002 totaled 229 Bcf, which was 9 Bcf below the 238 Bcf received in 2001. Whereas Algeria was formerly the largest LNG supplier to the United States (Figure 5), the largest in recent years has been the Atlantic LNG facility, located at Point Fortin in Trinidad and Tobago. In 2002, the largest volume of LNG (151 Bcf) to the United States came from Trinidad and Tobago, which was 66 percent of total U.S. LNG imports. The United States also received LNG spot cargos from Qatar (15 percent), Algeria (12 percent), Nigeria (4 percent), Brunei (1 percent), Oman (1 percent), and Malaysia (1 percent).

- **Pipeline exports to Mexico nearly doubled to 263 Bcf, the most natural gas ever exported to Mexico**. In all, natural gas is exported to Mexico at 11 points on the U.S.-Mexico borders in Texas, Arizona, and California. Exports of 76 Bcf at the U.S.-Mexican border at McAllen, Texas, on the newly constructed Coral-Mexico Pipeline accounted for about 29 percent of flows into Mexico, making McAllen the cross-border point with the largest share of exports to Mexico. About 22 percent of exports into Mexico, or about 59 Bcf, crossed the border near Clint, Texas, on El Paso Natural Gas' Samalayuca Pipeline. Opportunities to supply growing Mexican demand, particularly in the electric generation sector, continue the impetus for infrastructure growth at the border. El Paso early in 2002 received FERC permission to expand its Samalayuca lateral to serve two new power plants, one in El Encino and the other near the city of Juarez. North Baja Pipeline became operational on September 1, 2002. It is a 220-mile natural gas transportation pipeline originating at the California/Arizona border designed to serve growing energy demand in Baja California, Mexico, and portions of Riverside, Imperial, and San Diego counties in California.

Interstate Movements of Natural Gas Increased in 2002 for the Third Year in a Row

- **Flows of natural gas on the U.S. interstate gas transmission network grew by 4 percent in 2002, about the same expansion rate as in 2001.** Although several major gas transportation routes (Figure 6) did experience a small decline in gas flows (generally 3 percent or less) compared with 2001 levels, several others had significant gains (more than 10 percent), leading to the overall increase. Supporting this continued growth in flow was the construction of more than 3,571 miles of pipeline and the addition of a record 12.8 billion cubic feet per day (Bcf/d) of pipeline capacity to the national natural gas pipeline network during the year.[iii]

Figure 6. Major Natural Gas Pipeline Transportation Routes and 2002 Interstate Flow Levels at Selected Key Locations



•Percent change in flow from 2001. Bcf = Billion cubic feet.

Sources: Energy Information Administration: **Corridors:** Interstate Natural Gas Pipeline Capacity Database, **Flow:** Form EIA176 “Annual Report of Natural Gas and Supplemental Gas Supply and Disposition.”

- **The largest percentage increase in interstate pipeline deliveries occurred in the Florida marketplace.** Contributing to a 32-percent increase of gas into Florida in 2002 was the July 2002 start-up of the 1.1 Bcf/d Gulfstream Pipeline system, which now brings gas into the State from Alabama/Mississippi via a subsea pipeline, and the further expansion of the Florida Gas Transmission system to 2.0 Bcf/d at the end of 2002, which brings gas to the State from as far away as Texas. Both pipelines are meeting the increased gas demand from new gas-fired power plants recently built in the State. Since 1998, Florida’s yearly interstate gas receipts have increased from 473 Bcf to almost 700 Bcf in 2002, or 48 percent.

- **The southern California gas market reversed itself from 2001 with interstate gas deliveries declining significantly in 2002.** Deliveries into southern California (from Arizona and Nevada) fell from 1,488 Bcf in 2001 to 1,295 Bcf in 2002 (13 percent). This was due in part to a reduced gas demand in the power generation sector, brought about by a cooler-than-normal summer, increased fuel efficiency of newly installed gas-fired power plants in that part of the State, the closing of less efficient plants, and an increase in hydroelectric power generation as regional water levels recovered from an earlier drought.[iv] New gas-fired power plants in Arizona and Nevada helped mitigate the drop in California demand and helped absorb the increased flow of gas from the San Juan Basin (a 17-percent increase since 2001) and western Wyoming (on the Kern River Pipeline system).

- **Increases in production and pipeline capacity in the Rocky Mountain area in 2002 led to a 9-percent increase in interstate flows out of Wyoming and a 17-percent increase in flows from the San Juan Basin of southern Colorado/ northern New Mexico.** Gas production in Wyoming and Colorado increased by 7 and 3 percent, respectively, in 2002, as coalbed methane and conventional gas development continued to expand in the region. Both intrastate (gathering mainly) and interstate pipeline systems serving the area, including the Kern River 2001 system expansion toward Nevada/California markets and the Trailblazer 2002 system expansion directed to Midwestern markets, supported this growth (flows on the Trailblazer system increased about 28 percent, Kern River by 13 percent, in 2002). Expansion and increased pipeline flows from the San Juan Basin, most of whose incremental production is destined for the growing Arizona gas-fired power generation market, contributed to the installation of the new 87 million cubic feet per day (MMcf/d) Questar Southern Trails pipeline system and expansion of the area's Transwestern Pipeline system by 130 MMcf/d. Although its capacity did not expand during 2002, the Transcolorado Pipeline system, which serves both the San Juan and Piceance basins (northwest Colorado), saw its deliveries between Colorado and New Mexico increase by 49 percent from the 2001 level.

- **Several hurricanes in the Gulf of Mexico in the fall of 2002 contributed to an overall 2-percent decline in gas flowing out of the Texas/Louisiana/Mississippi/Alabama Gulf Coast area during the year.** Federal offshore gas production in the Gulf decreased by an estimated 7.0 percent, reflecting the impact of hurricanes and the natural decline in production over time. However, lesser decreases in onshore production in Texas and Alabama, along with increased production in Mississippi and large net withdrawals from storage throughout the region, yielded a lower decrease in the flow rate out of the area overall. In 2002, despite the decrease, the Southwest region still retained its position as the largest supplier of natural gas to Midwest, Northeast, and Southeast markets.

- **Deliveries of natural gas into the central Midwest (Chicago area hub) market declined by 3 percent in 2002 compared with 2001.** Although gas transportation into the area from Canadian and Rocky Mountain sources increased, it was not sufficient to compensate for the decreased gas availability from Gulf Coast sources. Deliveries from underground storage in Illinois during the year helped to make up for part of the difference. Net withdrawals from storage in 2002 in the State were 60 Bcf greater than in 2001.

- **Gas flows through South Carolina and North Carolina in the South Atlantic area decreased in 2002, as a larger percentage of the volumes transported on this corridor remained in the area, accommodating a 21-percent increase in regional gas demand.** The Transcontinental Gas Pipeline (Transco) system, which accounts for about 99 percent of the gas transported on this corridor, reflected a 5-to-6-percent drop in flow levels through the region in 2002 despite the increase in consumption on this portion of its system. Consequently, less gas than in previous years (about 60 Bcf) continued into the Northeast region on this segment of the Transco system. This shift in flows was accommodated by the installation of 415 MMcf/d of expansions on the northern Transco system between north central Pennsylvania and New York City in 2001-2002, and the use of that capacity to transport gas to customers on the East Coast as an alternative to the southern route. Flows on the expanded part of the northern Transco system increased by 2 percent (15 Bcf) in 2002.

Natural Gas Consumption

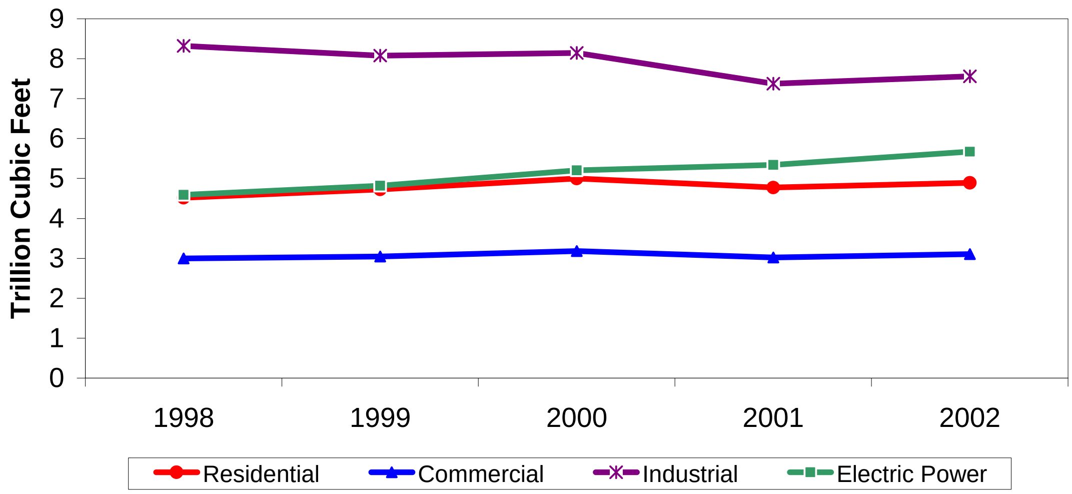
Natural Gas Consumption Increased in All End-Use Sectors

Total natural gas consumption increased to 23.0 Tcf after a slight decline in 2001. Although below the record high of 23.3 Tcf in 2000, total consumption in 2002 was the second-highest level ever. The net increase of 779 Bcf was driven primarily by increased deliveries to end-use customers, with the rest caused by increased use for pipeline fuel and plant use. The relative increase in consumption varied among the end-use sectors (Figure 7). More than 42 percent of the incremental deliveries to end users are attributable to deliveries to the electric power sector. In general, consumption growth likely was encouraged by prices that had declined from 2001 levels.

The expansion of residential and commercial consumption in 2002 reflected at least in part the influence of weather on these sectors. Heating degree-days for the year were slightly more than in 2001, contributing to almost 200 Bcf of additional consumption for the two sectors combined. The industrial sector increased its natural gas use by roughly 210 Bcf. Electric power continued its long-term expansion with a consumption increase of 330 Bcf. A primary factor contributing to this increase is a larger stock of gas-fired generation capacity. Vehicle use of natural gas also increased, although it remains an extremely small percentage of total consumption.

The consumption trends that have evolved in the past few years may have implications for natural gas markets. Consumption of natural gas for electric power not only increased in 2002, but it also expanded in each of the last 5 years, 1998-2002. At present, electric power use of gas is the second-largest consuming sector, and, after moving ahead of residential consumption in 1998, now exceeds residential volumes by almost 800 Bcf. Industrial use of natural gas during the same period has declined from 41 percent of the end-use market to less than 36 percent. The residential, commercial, and electric power consuming sectors exhibit seasonal variation in their consumption. Consequently, the share of the market driven by seasonal factors is growing.

Figure 7. U.S. Natural Gas Consumption by Sector, 1998-2002



Some additional highlights related to the consumption data follow.

Increased Heating Demand Contributed to Consumption Increases in the Residential and Commercial Sectors

- **Total residential consumption increased to 4,890 Bcf, or 2.5 percent**. A key factor for the increase was an increase in cumulative total heating-degree-days (HDD), owing primarily to much colder temperatures from October through December 2002. For the United States as a whole, HDDs for the year were 4.0 percent higher than in 2001.

- **Total commercial consumption increased by 80.6 Bcf, or 2.7 percent, to 3,103.3 Bcf**. Thirty-one States and the District of Columbia recorded increases ranging from 1.8 Bcf in the New England States to 29.8 Bcf in New York and New Jersey. The States of Washington, Ohio, and California ranked first through third, respectively, among States with decreased commercial consumption. With a combined decrease of nearly 28.0 Bcf, these three States accounted for nearly 62 percent of the total decline in the 19 States with decreased commercial consumption.

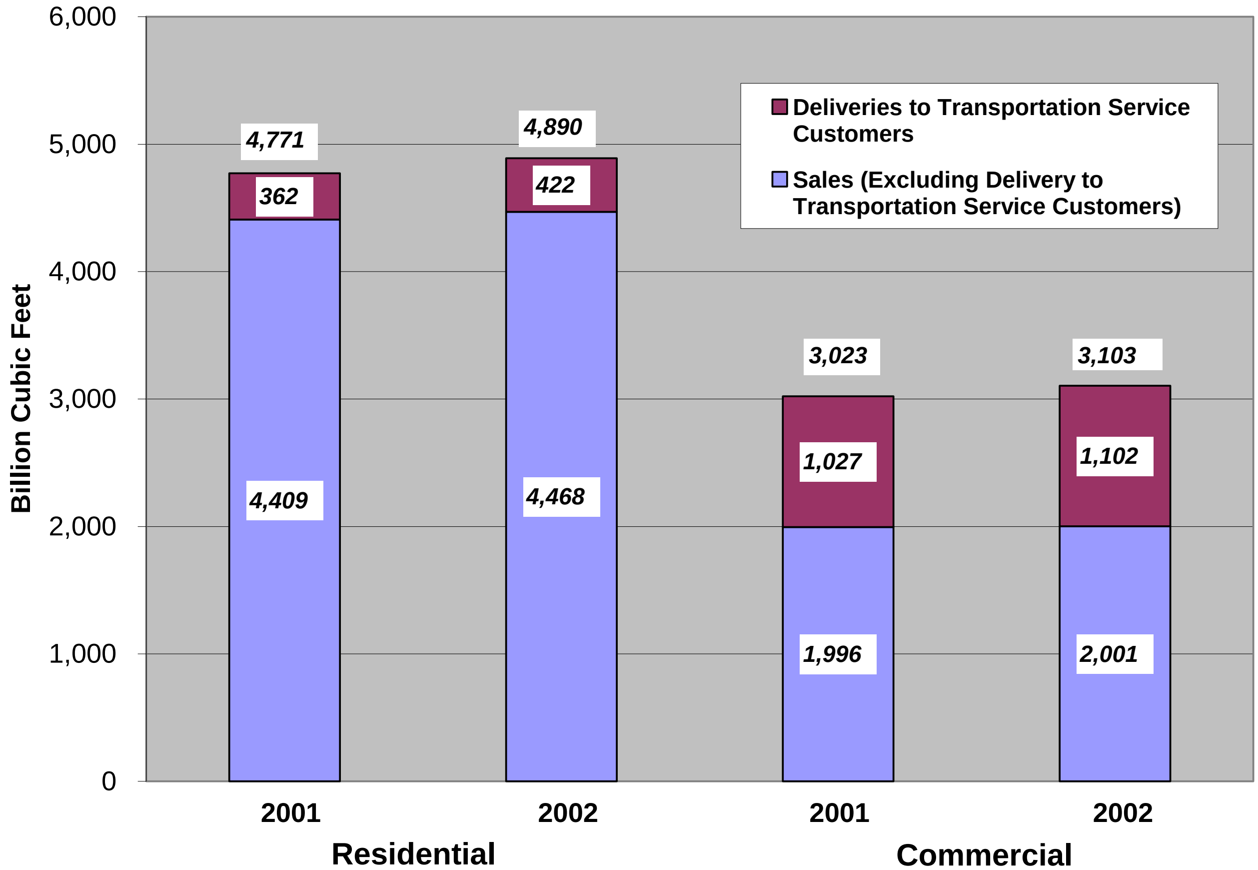
- **Thirty-three States and the District of Columbia had increased residential consumption**, with gains ranging up to 21 percent. Illinois and Michigan had the largest increases in volumes consumed, at 32.1 and 25.0 Bcf, respectively, while Wyoming had the largest percentage increase, at 21.4 percent.

- **Seventeen States had decreased residential consumption, ranging from less than 1 percent to more than 13 percent of their 2001 levels**. The State of Washington had the largest decrease in both volumetric and percentage terms: 11.1 Bcf, or 13.1 percent. The second-largest volume decrease occurred in New York State, with a decrease of 6.6 Bcf, or almost 2 percent.

- **California accounted for the largest share of residential consumption of the States, at 10.5 percent of the national total, while New York has the largest share of commercial consumption, at 11.7 percent**. As in years past, eight States (California, Illinois, New York, Michigan, Ohio, Pennsylvania, Texas, and New Jersey) account for over half of both total residential and total commercial consumption. This group's shares in these categories were unchanged from 2001, at 55 and 52 percent, respectively.

- **At the national level, deliveries for commercial transportation customers accounted for more than 93 percent of the net increase in total commercial volumes delivered** (Figure 8), even though the number of transportation-service commercial customers increased by only 1.1 percent from 2001 levels.

Figure 8. Sales and Transportation Deliveries, Residential and Commercial Sectors

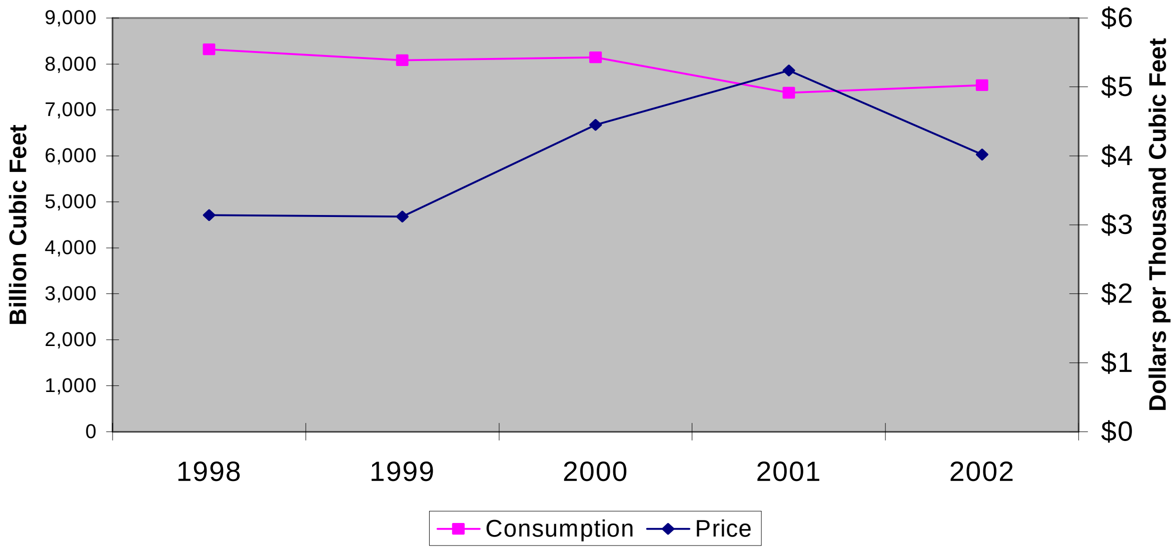


Industrial Consumption Was Driven by Prices and Economic Growth

- **Economic gains and lower prices contributed to a 2.9-percent increase in industrial use of natural gas in 2002 in comparison with the nearly 10-percent decline between 2000 and 2001** (Figure 9)**.** U.S. real gross domestic product increased by 2.4 percent from 2001 to 2002.[v] Some of the gas-consuming manufacturing establishments that had reduced activity or shut down in 2001, or turned to alternative fuels because of relatively high prices, returned to service in 2002.

- **Three States, California, Louisiana, and Texas, accounted for around 47 percent of total industrial usage in 2002,** in part because of their extensive refining capacity. These three States rank highest in the country in refining capacity, and in 1998 (most recent data available) petroleum refineries used about 13 percent of the total natural gas used by all manufacturers.[vi] In addition to petroleum refineries, the largest consumers of natural gas in the manufacturing sector are chemical producers (around 36 percent of total usage) and primary metals (about 13 percent). Natural gas usage in the fertilizer industry (a part of chemical manufacturing) is generally as a feedstock so is particularly sensitive to natural gas costs. In 2002, production of ammonia, which is a main ingredient in fertilizer production, increased by 15 percent and capacity utilization increased from 56 percent to 79 percent,[vii] partly as a result of lower relative gas prices in 2002.

Figure 9. Natural Gas Industrial Consumption and Prices, 1998-2002



Consumption of Natural Gas for Electric Power Generation Continued Growing

- **In 2002, natural gas consumed for generation of electric power increased to 5.7 Tcf, or 6.2 percent more than the 2001 volume**. The electric power sector is second only to the industrial sector in end-use consumption and now accounts for 27 percent of natural gas delivered to consumers. Further, gas consumption has grown by 24 percent since 1998 in the electric power sector as a result of the large build-up during the past couple of years of gas-fired generation plants, which have been viewed by industry as more environmentally and economically advantageous than other fuels for electric generation. In 2002, approximately 51,000 megawatts fueled by natural gas came online. This was approximately 93 percent of the electric generation capacity that came online during the year.

- **Five States accounted for approximately 61 percent of the natural gas consumed in the electric power sector** (Figure 10). The State with the largest consumption of natural gas in the sector during 2002 was Texas, which consumed approximately 1.6 Tcf, or 27 percent of the 5.7 Tcf consumed by the sector. The next four largest consuming States are California (727 Bcf), Florida (522 Bcf), New York (366 Bcf), and Louisiana (324 Bcf). The largest year-to-year changes in consumption occurred in California, where consumption dropped 247 Bcf from the 2001 level as a cooler-than-normal summer dampened demand for air-conditioning. In Florida, where several new gas-fired units came online during the year, consumption increased by 148 Bcf.

Figure 10. Leading Consuming States for Deliveries of Natural Gas for Electric Power Generation

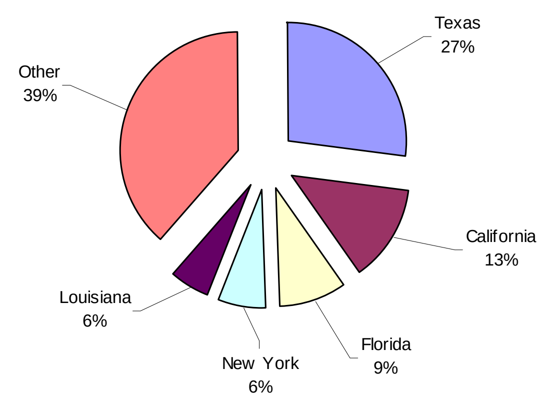
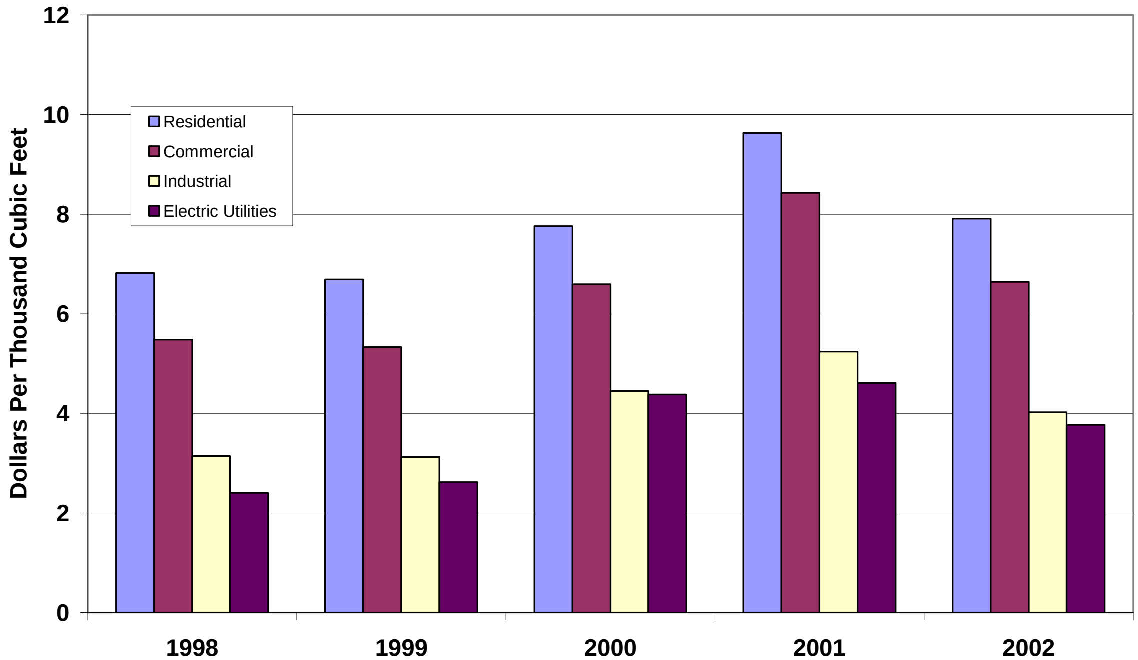


Figure 11. Natural Gas Prices by Major End-Use Sectors, 1998-2002



Note: Vehicle fuel end-use prices not shown.

Prices to All End-Use Sectors Declined

- **End-use consumer prices decreased in each sector of the natural gas market in 2002** (Figure 11). Prices declined 18 percent in the residential sector, 21 percent in the commercial sector, 23 percent in the industrial sector, and 18 percent in the electric utility sector. This ended a 2-year pattern in which prices increased in each of the sectors, and a 3-year pattern of price hikes in the electric utility sector.

- **Measured in constant dollars, sector prices in 2002 declined to their lowest levels in 3 years, falling beneath the levels that prevailed in 2000 (2002 dollars).** The price declines in 2002 reversed the upward trend of natural gas end-use prices. In the residential and commercial sectors, prices fell 2 percent and 4 percent below the 2000 level, respectively. In the industrial and electric sectors, the declines were pronounced, falling 14 and 18 percent below the 2000 level, respectively. Nevertheless, prices remain near their historical highs. For example prices in both the residential and commercial sectors were at the third-highest level since 1987.

- **Residential and commercial consumers continued to pay the highest prices for natural gas, at $7.91 and $6.64 per Mcf, respectively.** This reflects the limited options in service, the higher distribution costs to these sectors, and the high-quality services required during peak demand periods.

- **Industrial companies and electric utilities are large-volume customers with relatively high load factors, which enable them to take advantage of economies of scale in natural gas purchases.** Additionally, they are typically in a better position to elect whether to stay with their local distribution company, seek gas supplies from alternative sources, or switch to other fuels. The average prices paid by the industrial and electric utility sectors were $4.02 and $3.77 per Mcf, respectively.

- **The average price for natural gas at the city gate decreased by more than 27 percent from 2001 to 2002, falling to $4.15 per Mcf.** City gate prices represent the total cost paid by gas distribution companies for gas received at the point where gas is physically transferred from a pipeline company or transmission system to the local distribution company (LDC). This price reflects all charges for the commodity, storage, and transportation associated with the LDC obtaining natural gas for sale to consumers.

[i] Energy Information Administration, *Natural Gas Monthly*, November 2003.

[ii] The storage region identified here corresponds with the regions for underground natural gas storage in EIA's *Weekly Natural Gas Storage Report*.

[iii] Energy Information Administration, *Expansion and Change on the U.S. Natural Gas Pipeline Network – 2002*, (http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/pipenet03.html).

[iv] Energy Information Administration, *Electric Power Monthly March 2003,* Tables 10, 11, 64, and 65, DOE/EIA-0226 (Washington, DC, January 2004).

[v] Based on Energy Information Administration, *Annual Energy Review*, Appendix D.

[vi] Energy Information Administration (http://www.eia.doe.gov/emeu/mecs/mecs98/datatables/d98n1_1.pdf).

[vii] U.S. Geological Survey Minerals Yearbook, years 2001 and 2002 (http://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/).