Natural Gas

Natural gas is the fastest growing primary energy source in the IEO2003 forecast. Consumption of natural gas is projected to nearly double between 2001 and 2025, with the most robust growth in demand expected among the developing nations.

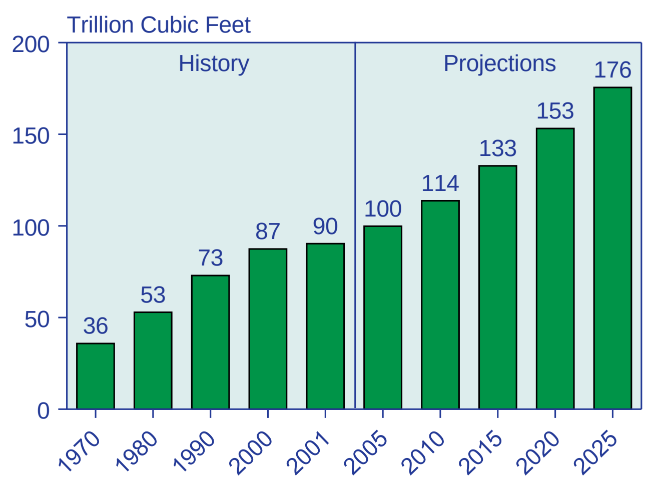
Natural gas is expected to be the fastest growing component of world primary energy consumption in the *International Energy Outlook 2003* (*IEO2003*) reference case. Consumption of natural gas worldwide is projected to increase by an average of 2.8 percent annually from 2001 to 2025, compared with projected annual growth rates of 1.8 percent for oil consumption and 1.5 percent for coal. Natural gas consumption in 2025, at 176 trillion cubic feet, is projected to be nearly double the 2001 total of 90 trillion cubic feet (Figure 40). The natural gas share of total energy consumption is projected to increase from 23 percent in 2001 to 28 percent in 2025.

The most robust growth in natural gas demand is expected among the nations of the developing world, where overall demand in the reference case rises by 3.9 percent per year between 2001 and 2025. The level of natural gas use in the developing world by 2025 is projected to be two and one-half times the 2001 level (Figure 41). Much of the growth in the region is expected to fuel electricity generation, but infrastructure projects are also underway for natural gas to displace polluting home heating and cooking fuels in major urban areas, such as Beijing and Shanghai.

Industrialized countries, where natural gas markets are most mature, also are projected to increase their reliance on natural gas. Over the next 24 years, demand for natural gas in the industrialized world is expected to increase by 2.2 percent annually, almost twice the rate of increase projected for oil. Among the industrialized regions, North America is expected to have the largest increment in natural gas use between 2001 and 2025, at 19 trillion cubic feet (Figure 42). The United States alone accounts for 66 percent of the total North American increment in gas consumption. In the United States, natural gas demand is expected to rise by 1.8 percent annually, mainly for electricity generation. Of the new generating capacity projected for the United States, 80 percent is expected to be natural-gas-fired combined-cycle or combustion turbine technology, including distributed generation capacity.

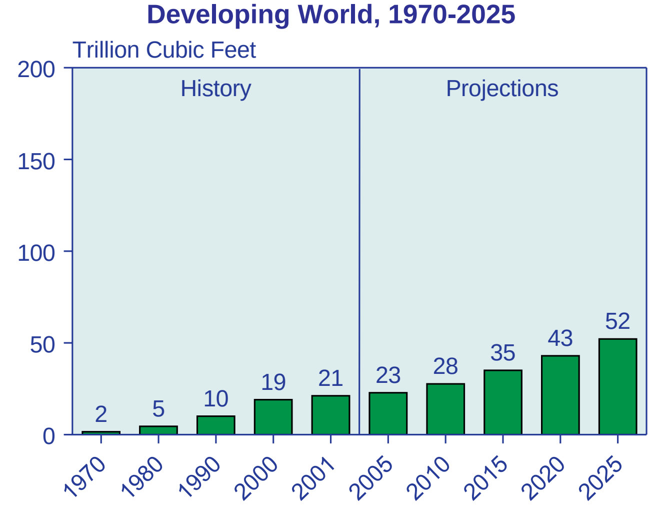
Rapid growth in natural gas use is projected for Mexico, at 6.1 percent per year over the projection period. The industrial and electric utility sectors are expected to account for most of the growth, and some increase for residential and commercial sector use are expected as a result of the 1995 privatization of the transmission and

Figure 40. World Natural Gas Consumption, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

Figure 41. Natural Gas Consumption in the Developing World, 1970-2025



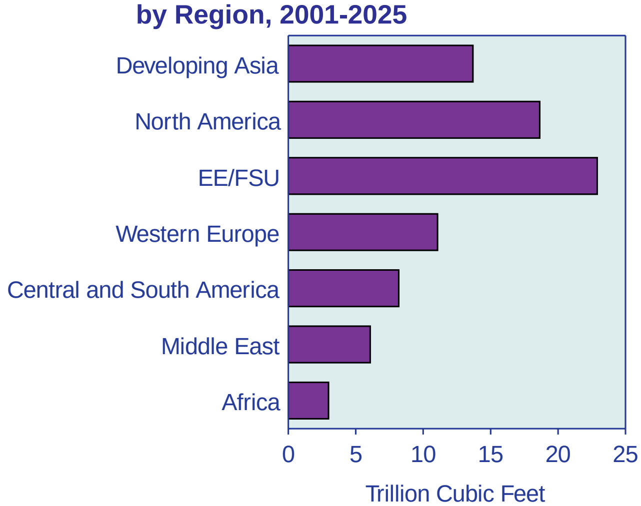
Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

distribution sector, which has brought natural gas service to a number of cities for the first time.

Western Europe is also expected to expand its use of natural gas strongly over the projection period, at an average annual rate of 2.4 percent. Liberalization of natural gas markets in the European Union has been underway since the passage of the Natural Gas Directive in 1998, and in a majority of the member countries, natural gas infrastructures are expected to be fully open to third-party access by 2008. Increases in natural gas use for electricity generation are expected in many Western European countries, replacing many old coal-fired generators and nuclear power plants set to retire in the coming decades. Total natural gas consumption in Western Europe is expected to increase from 14.8 trillion cubic feet in 2001 to 25.9 trillion cubic feet in 2025.

In Eastern Europe and the former Soviet Union (EE/FSU), natural gas consumption is expected to increase by 2.9 percent annually between 2001 and 2025. The fastest rates of growth in the region are projected for the countries of Eastern Europe, where economic recovery has been underway since the collapse of the Soviet Union, and the economies of the region continue to align with their wealthier Western European neighbors. Eastern Europe's demand for natural gas is expected to grow by 4.6 percent per year in the forecast. An infrastructure that is fast becoming integrated with Western Europe supports the growth in East European gas use. In the FSU, natural gas demand is expected to increase at a somewhat slower pace, 2.6 percent per year. There has been some progress in restructuring the natural gas markets in the FSU, and several years of positive economic growth indicate that sustained economic recovery is now underway.

Figure 42. Increases in Natural Gas Consumption by Region, 2001-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

The amount of natural gas traded across international borders continues to grow, increasing from barely 19 percent of the world's consumption in 1995 to 23 percent in 2001 [***1***]. Pipeline exports grew by 39 percent and liquefied natural gas (LNG) trade grew by 55 percent between 1995 and 2001. Numerous international pipelines are either planned or already under construction. Projected increases in world natural gas consumption will require bringing new gas resources to market. The fact that many sources of natural gas are far from demand centers, coupled with cost decreases throughout the LNG chain, has made LNG increasingly competitive, contributing to the expectation of strong worldwide growth for LNG.

The economics of transporting natural gas to demand centers currently depend on the market price, and the pricing of natural gas is not as straightforward as the pricing of oil. More than 50 percent of the world's oil consumption is traded internationally, whereas natural gas markets tend to be more regional in nature, and prices can vary considerably from country to country. In Asia and Europe, for example, LNG markets are strongly influenced by oil product markets rather than by natural gas prices. As the use and trade of natural gas continue to grow, it is expected that pricing mechanisms will continue to evolve, facilitating international trade and paving the way for a global natural gas market.

Reserves and Resources

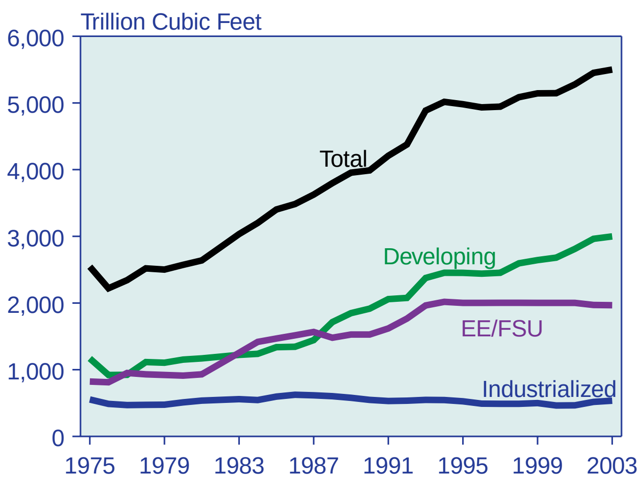
Since the mid-1970s, world natural gas reserves have generally trended upward each year (Figure 43). As of January 1, 2003, proved world natural gas reserves,[3] as reported by *Oil & Gas Journal*, were estimated at 5,501 trillion cubic feet, 50 trillion cubic feet more than the estimate for 2002. Most of the increase is attributed to developing countries, where gas reserves have increased by 37 trillion cubic feet since last year's survey. Natural gas reserves in the industrialized countries also increased between 2002 and 2003, by 18 trillion cubic feet. EE/FSU reserves declined by 4 trillion cubic feet—primarily because of lowered estimates for Turkmenistan, where reserves declined by 30 trillion cubic feet. The decrement was largely offset by the enormous upward revision to Azerbaijan gas reserves in this year's survey, from 4 trillion cubic feet in 2002 to 30 trillion cubic feet in 2003.

[3]Proved Reserves, as reported by the *Oil & Gas Journal*, are estimated quantities that can be recovered under present technology and prices. Figures reported for Canada and the former Soviet Union, however, include reserves in the probably category. Natural gas reserves reported by the *Oil & Gas Journal* are compiled from voluntary survey responses and do not always reflect the most recent changes. Significant gas discoveries made during 2002 are not likely to be reflected in the reported reserves.

Most (about 71 percent) of the world's natural gas reserves are located in the Middle East and the EE/FSU (Figure 44), with Russia and Iran together accounting for about 45 percent of the world's natural gas reserves (Table 17). Reserves in the rest of the world are fairly evenly distributed on a regional basis.

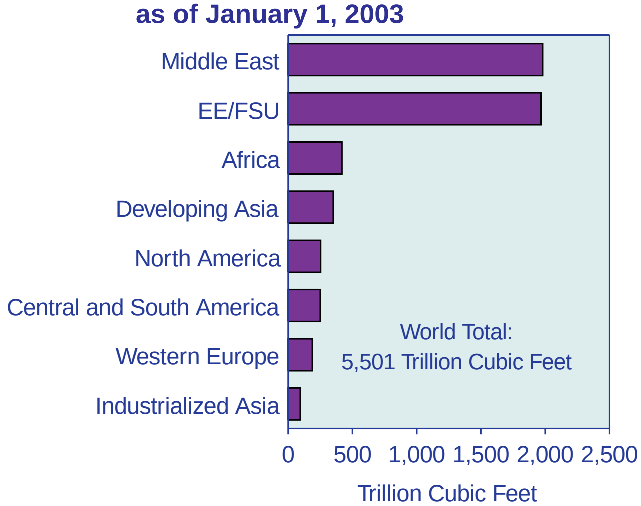
Despite high rates of increase in natural gas consumption, particularly over the past decade, most regional reserves-to-production ratios have remained high. Worldwide, the reserves-to-production ratio is estimated at 61.9 years [*2*]. Central and South America has a reserves-to-production ratio of 71.6 years, the FSU 78.5 years, and Africa 90.2 years. The Middle East's reserves-to-production ratio exceeds 100 years.

Figure 43. World Natural Gas Reserves by Region, 1975-2003



Sources: **1975-1993:** "Worldwide Oil and Gas at a Glance," *International Petroleum Encyclopedia* (Tulsa, OK: PennWell Publishing, various issues). **1994-2003:** *Oil & Gas Journal* (various issues).

Figure 44. World Natural Gas Reserves by Region as of January 1, 2003



Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 100, No. 52 (December 23, 2002), pp. 114-115.

The largest expansion in worldwide natural gas reserves between 2002 and 2003 occurred in Western Europe, where 31 trillion cubic feet was added to the region's reserve base. This increment in reserves is entirely attributable to Norway, where reserves grew by 33 trillion cubic feet as a result of recent new gas finds, including Statoil's Tyrihans South discovery of oil and gas in the Norwegian Sea [*3*]. The increment in Norwegian reserves more than offset minor decrements in other Western European countries—including the United Kingdom, the Netherlands, and Germany—and placed Norway among the top 20 countries with respect to proven natural gas reserves.

U.S. proven gas reserves increased by 6 trillion cubic feet and Canadian reserves increased by less than 1 trillion cubic feet, but Mexico's reserves dropped by nearly 21 trillion cubic feet between 2002 and 2003. Petroleos Mexicanos revised its estimate of national oil and natural gas reserves downward in September 2002 to comply with U.S. Securities and Exchange Commission filing guidelines [*4*]. Natural gas reserves in industrialized Asia increased slightly in 2003, by about 1 trillion cubic feet, as a result of new finds in New Zealand.

Table 17. World Natural Gas Reserves by Country as of January 1, 2003

Country	Reserves (Trillion Cubic Feet)	Percent of World Total
World	**5,501**	**100.0**
Top 20 Countries	**4,879**	**88.7**
Russia	1,680	30.5
Iran	812	14.8
Qatar	509	9.2
Saudi Arabia	224	4.1
United Arab Emirates	212	3.9
United States	183	3.3
Algeria	160	2.9
Venezuela	148	2.7
Nigeria	124	2.3
Iraq	110	2.0
Indonesia	93	1.7
Australia	90	1.6
Norway	77	1.4
Malaysia	75	1.4
Turkmenistan	71	1.3
Uzbekistan	66	1.2
Kazakhstan	65	1.2
Netherlands	62	1.1
Canada	60	1.1
Egypt	59	1.1
Rest of World	**622**	**11.3**

Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 100, No. 52 (December 23, 2002), pp. 114-115.

Among the regions of the developing world, Africa and Asia had the largest revisions in proved natural gas reserves between 2002 and 2003. In Africa, the entire increment of 23 trillion cubic feet in gas reserves is attributable to Egypt, where a marked increase in exploration activity over the past few years has resulted in a substantial increase in gas reserves, including finds in the Western Desert, Gulf of Suez, Mediterranean Sea, and Nile Delta [***5***]. Developing Asia saw an increase in reserves of 11 trillion cubic feet over the past year. Among the developing Asian countries, the greatest increases in proven reserves were in China and India, where reserves grew by 5 trillion cubic feet and 4 trillion cubic feet, respectively. Modest increases were made in Pakistan, the Philippines, and Thailand.

The U.S. Geological Survey (USGS) periodically assesses the long-term production potential of worldwide petroleum resources (oil, natural gas, and natural gas liquids). According to the most recent USGS estimates, released in the *World Petroleum Assessment 2000*, a significant volume of natural gas remains to be discovered. The mean estimate for worldwide undiscovered gas is 4,839 trillion cubic feet (Figure 45), which is approximately double the worldwide cumulative consumption forecast in *IEO2003*. A further 3,000 trillion cubic feet is estimated to be in "stranded" reserves, usually located too far away from pipeline infrastructure or population centers to make transportation of the natural gas economical.

Of the new natural gas resources expected to be added over the next 25 years, reserve growth accounts for 2,347 trillion cubic feet. More than one-half of the mean undiscovered gas estimate is expected to come from the former Soviet Union, the Middle East, and North Africa, and about one-third (1,169 trillion cubic feet) is expected to come from a combination of North, Central, and South America. It is estimated that about one-fourth of the undiscovered natural gas reserves worldwide are in undiscovered oil fields.

Although the United States has produced more than 40 percent of its total estimated natural gas endowment and carries less than 10 percent as remaining reserves, in the rest of the world reserves have been largely unexploited. Outside the United States, the world has produced less than 10 percent of its total estimated natural gas endowment and carries more than 30 percent as remaining reserves.

Regional Activity

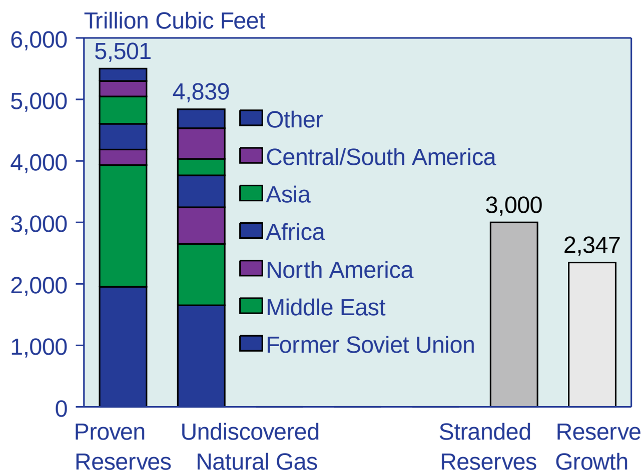
North America

Natural gas consumption in North America is projected to grow by 2.2 percent per year on average between 2001 and 2025 (Figure 46). Demand for gas is projected to increase in all three countries of the region (Canada, Mexico, and the United States), with the highest rate of growth projected for Mexico. The expanding gas infrastructure in Mexico is expected to be particularly focused on providing gas to electric power stations. The Canadian and U.S. natural gas markets are already well integrated. As additional infrastructure is built in Mexico and between Mexico and the United States, it is expected that an increasingly integrated natural gas market will serve the entire region.

United States

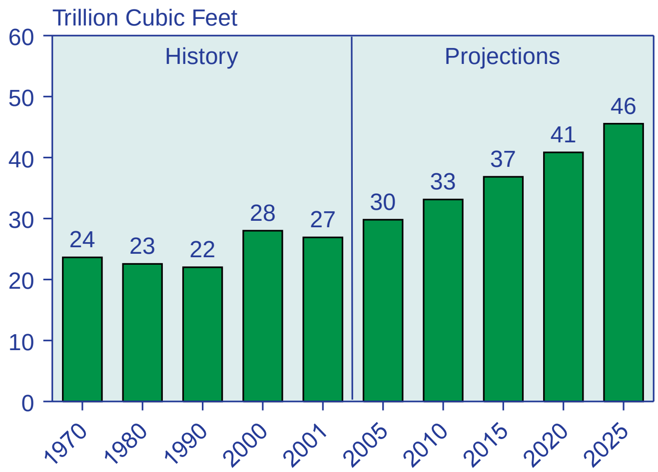
The United States continues to be the largest producer and consumer of natural gas in North America. Total

Figure 45. World Natural Gas Resources by Region as of January 1, 2003



Source: U.S. Geological Survey, *World Petroleum Assessment 2000*, web site http://greenwood.cr.usgs.gov/energy/WorldEnergy/DDS-60; "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 100, No. 52 (December 23, 2002), pp. 114-115.

Figure 46. Natural Gas Consumption in North America, 1970-2025



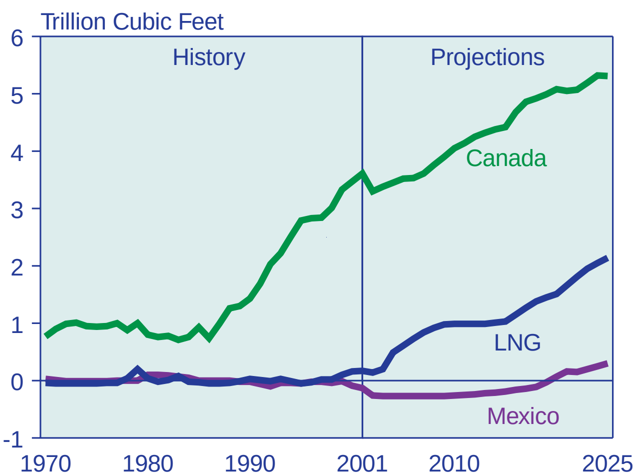
Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

U.S. natural gas consumption is projected to increase from 22.6 trillion cubic feet in 2001 to 34.9 trillion cubic feet in 2025. The largest increase in U.S. gas consumption is expected to occur in the electricity generation sector, which is projected to consume 10.6 trillion cubic feet in 2025 [*6*]. Both U.S. production and imports of natural gas are expected to grow. In 2025, net Canadian gas imports are expected to provide 15 percent of total U.S. consumption, which is about the same proportion being supplied by Canada today. This projection of Canadian gas exports to the United States expects that the MacKenzie Delta gas pipeline will begin operation in 2016. An additional 6 percent of total U.S. natural gas consumption, or 2.1 trillion cubic feet, is projected to be supplied by LNG imports (Figure 47). Mexico is expected to become a net exporter of natural gas to the United States after 2019, assuming the construction of an LNG regasification terminal in Baja, Mexico.

In 2000 and 2001, new U.S. gas discoveries replaced 99.6 and 115.1 percent of the natural gas produced during those years [*7*]. Gas producers, however, are not so sanguine about the future. There has been considerable discussion within the industry that a lack of good gas drilling prospects might lead to future U.S. supply problems [*8*].

A number of recent legislative proposals and market developments in the United States may have long-term implications for the U.S. natural gas market. On the legislative side, during much of 2002, major energy bills were debated in the U.S. Congress, particularly the House of Representatives Bill 4 (H.R. 4) and Senate Bill 1766 (S. 1766). S. 1766 originally proposed a Federal loan

Figure 47. Net U.S. Imports of Natural Gas, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, *Annual Energy Outlook 2003*, DOE/EIA-0383(2003) (Washington, DC, January 2003), Table A13.

guarantee for an Alaskan gas pipeline, which would have guaranteed 80 percent of the principal of any loan made to finance its construction. The loan guarantee was capped at $10 billion. A later amendment to S. 1766 would have provided additional financial support for the Alaska gas pipeline in the form of an income tax credit, which would have become effective when the average monthly price of natural gas at AECO C Hub in Alberta fell below $3.25 per million Btu. Any tax credit collected by shippers would then be subject to being paid back when the benchmark price went above $4.88 per million Btu. H.R. 4 called for the establishment of a Federal leasing program that would open the Alaskan National Wildlife Refuge (ANWR) to oil and gas production. Both the House and Senate bills called for the restoration of Section 29 tax credits for coalbed methane production. Deadlock on a host of issues associated with these bills prevented the Congress from passing any comprehensive energy bill during its last session.

On January 10, 2003, the U.S. Bureau of Land Management released the "Final Environmental Impact Statement and Proposed Plan Amendment for the Powder River Basin Oil and Gas Project." This long-delayed Environmental Impact Statement (EIS) has constrained coalbed methane development in Wyoming's Powder River Basin, because development in the area could not proceed without approval of the EIS [*9*]. Although a number of issues were addressed in the EIS, the primary issue associated with coalbed methane production is the disposal of water produced in conjunction with the natural gas. Currently, large amounts of water are being discharged directly on the surface rather than being reinjected into the ground. Coalbed methane producers are concerned that a reinjection requirement might be uneconomical. In contrast, land owners are concerned that the surface discharge of water will contaminate streams and aquifers with salty water. Although the EIS contains a preferred plan for water disposal, it provides only an analytical basis for Government decisions. In the formation of those decisions, the issue of water disposal is likely to remain contentious.

Access to Federal lands has been a perennial political issue for the natural gas industry, because a considerable portion of the entire U.S. gas resource base both onshore and offshore is under Federal lease jurisdiction. Some of the gas resources under Federal lands are completely precluded from development, and development of others is constrained by Federal lease stipulations [*10*]. In November 2000, Congress passed the Energy Policy and Conservation Act Amendments of 2000 (EPCA), which required Federal agencies to conduct an inventory of oil and gas resources beneath onshore Federal lands. The inventory was to quantify the volumes of oil and gas resources on Federal lands and to determine the nature and extent of any restrictions or impediments to their development. Because most of the Federal lands affected are located in the Rocky Mountain States, the EPCA Federal inventory focused exclusively on five major petroleum basins in the region. In January 2003, the results of the Federal oil and gas resource inventory were published [**11**]. The study found that of the 138.5 trillion cubic feet estimated to be under Federal lands in the Rocky Mountain region, approximately 11.5 percent is under Federal lands where no leasing is permitted, and another 26 percent is subject to lease restrictions. The remaining 62.5 percent can be leased under standard Federal lease terms with no restrictions [**12**].

On December 18, 2002, the U.S. Federal Energy Regulatory Commission (FERC) announced a new regulatory policy for LNG regasification terminals [**13**]. The FERC announced that new U.S. LNG terminals would no longer be subject to the Commission's open-access and cost-of-service regulations. Owners would be permitted to operate new LNG terminals on a private contract basis and charge market-based rates. The regulatory change was requested by LNG project sponsors, who wanted assurance that LNG supplies produced overseas by their corporate subsidiaries could be guaranteed access to the U.S. market through their proprietary terminals. The FERC's decision also reduces the financial risk associated with new LNG facilities, because their profitability and the profitability of parent companies' upstream facilities (i.e., overseas gas production and liquefaction facilities and LNG tankers) will no longer be constrained by a tariff rate cap. Collectively, these changes are expected to reduce LNG project risk and thus enhance the financial incentive to build new LNG facilities.

Although the financial risk of building new LNG terminals has been reduced by the new FERC policy, other industry developments have impaired the financial circumstances of several LNG project sponsors. For example, Enron Corporation filed for Chapter 11 reorganization in December 2001, and Dynegy Inc. reported a $2.8 billion net loss for 2002. Similarly, AES Corporation reported a 2002 net loss of $3.5 billion, and El Paso Corporation's financial difficulties are reflected in its decision to sell $3.4 billion of assets during 2003 [**14**]. These four financially challenged companies are unlikely to build the LNG facilities they had proposed. The four companies had previously announced intentions to build approximately 1.6 trillion cubic feet of new LNG regasification capacity in the United States [**15**].

Another potential casualty of recent financial problems is the future implementation of the El Paso "Energy Bridge" LNG concept. The construction of new onshore LNG terminals is expected to encounter considerable local political opposition. Such opposition, for example, was cited as one reason for Shell U.S. Gas and Power's decision to end its participation in a proposal to build the Mare Island LNG terminal [**16**]. The El Paso "Energy Bridge" concept was to build floating offshore docks that would allow LNG tankers to unload their cargoes out of sight of land. It was hoped that the approach would eliminate the political opposition associated with onshore facilities. Now that El Paso has decided to exit the LNG business, this innovative approach to building and operating new LNG terminals might go untested for some time.

Many large U.S. corporations have abandoned or reduced activities in natural gas trading, marketing, and brokering as a result of financial difficulties. Industry participants are concerned that the exit of gas traders will reduce the liquidity and therefore the transparency of U.S. natural gas markets, leading to increased price volatility and uncertainty [**17**]. Increased uncertainty about future natural gas prices, in turn, would increase the cost of capital for natural gas exploration and development [**18**].

Another issue that has arisen is whether a gas pipeline will be built to transport stranded Alaskan North Slope gas to the lower 48 gas consumption market. Interest in building an Alaskan gas pipeline was revived during the winter of 2000-2001, when natural gas prices were relatively high. In May 2002, BP, ExxonMobil, and ConocoPhillips released a joint study that evaluated the economics of constructing a gas pipeline from the Alaska North Slope to the lower 48 States [**19**]. The primary conclusions of the financial analysis were that a pipeline built from the North Slope Alaska to Chicago would cost approximately $18.6 to $19.4 billion dollars[4] to build (depending on the route used), and that the pipeline's transportation tolls to the lower 48 States would be between $2.31 to $2.39 per thousand cubic feet. Even though North Slope oil and gas producers continue to be interested in building an Alaskan gas pipeline, as witnessed by their continued efforts to reduce pipeline capital costs and regulatory uncertainty, there are no current indications that the pipeline's construction would be completed before 2010 [**20**].

Canada

Natural gas consumption in Canada is projected to grow at a rate of 2.3 percent per year between 2001 and 2025. In 2000, approximately 53 percent of Canada's dry gas production of 6.3 trillion cubic feet was exported to the United States [**21**]. By 2025, net exports of natural gas from Canada to the United States are projected to be 5.3 trillion cubic feet in the *IEO2003* reference case, and Canada's own consumption is projected to be 5.0 trillion cubic feet [**22**]. The Canadian National Energy Board (NEB) estimates that Canada has an undiscovered potential conventional gas resource base of between 389 and 460 trillion cubic feet [**23**].

[4]The cost estimates include the cost of constructing a natural gas treatment plant and a natural gas liquids extraction plant.

Although Canada's natural gas resources appear adequate for the period through 2025, some concerns have been raised about the future viability of finding and developing conventional gas resources. Even though new Canadian gas discoveries in 2001 replaced 106 percent of its gas production, some producers are concerned that depletion of conventional gas resources might cause development costs to escalate rapidly, especially in the Western Canadian Sedimentary Basin (WCSB), which is the primary source of Canada's conventional gas supplies [**24**]. A recent NEB report [**25**] summarizes the situation in the following manner:

> *An average gas recovery for 2001 connections will be less than 25 percent of the average gas recovery for 1995 connections. These large reductions in gas recovery per connection correlate with the diminishing gas supply response to increasing drilling activity. To compensate for the lower recovery per connection, an increasing number of wells has to be drilled to increase or even maintain overall natural gas production from the WCSB.*

Concern about WCSB conventional gas resources has also been raised by the rapid production decline of the Ladyfern gas field, which is thought to contain 1 trillion cubic feet of recoverable gas and is the largest onshore gas accumulation found in North America over the past 15 years. By the close of March 2002, 40 Ladyfern wells were producing 785 million cubic feet per day, 5 percent of Canada's natural gas stream. In June 2002, however, the field was producing only 650 million cubic feet per day, and by the end of 2002 it was expected to be producing only 450 million cubic feet per day [**26**].

Similar concerns are being expressed with regard to the size of the offshore Atlantic undiscovered gas resource base. Although the offshore Atlantic is thought to have as much as 63 trillion cubic feet of ultimate resources,[5] no large discoveries have been made since the Deep Panuke field (1 trillion cubic feet) was discovered in 1999 [**27**]. The Deep Panuke is the only new gas field expected to go into operation by 2006 (at 400 million cubic feet per day) and only the second offshore gas field to go into production in East Canada (after Sable Island). Since 1999, exploration results have generally been disappointing, and a number of dry wells have been drilled. In August 2002, however, the deepwater gas discovery by EnCana and Marathon Oil revived hopes for more large finds. The lack of commercial gas discoveries in the offshore Atlantic caused Eastern Canadian gas reserves to decline in 2002 by an amount equal to the annual gas production of the Sable Offshore Energy Project, about 190 billion cubic feet. Given the concerns about depletion of conventional gas resources in both the WCSB and offshore Atlantic regions, Canadian producers are considering the commercial viability of both conventional Arctic gas resources and other unconventional gas resources, especially coalbed methane and gas hydrates.

In the Arctic region of the MacKenzie Delta-Beaufort Sea (MacKenzie), 9 trillion cubic feet of marketable natural gas reserves has sparked interest in the construction of a gas pipeline into Alberta [**28**]. Another 55 trillion cubic feet is expected to be discovered [**29**]. Given the perceived decline in WCSB conventional gas resources, producers have discussed the development of Canada's Arctic gas resources since 2001. One proposal called for about 1 billion cubic feet per day of MacKenzie gas to be transported by an Alaskan gas pipeline, which would have started on the Alaska North Slope, crossed the Beaufort Sea to MacKenzie, and then proceeded south to Alberta. The proposal was scuttled by the Alaska State Legislature, which mandated that an Alaska North Slope gas pipeline first go to Fairbanks and then proceed along the Alaska Highway before entering Alberta. Since then, the MacKenzie Delta pipeline has been envisioned as a standalone pipeline [**30**].

Given the uncertainty surrounding the construction of an Alaska gas pipeline and the expected growth in consumption of Canadian natural gas in both U.S. and Canadian markets, some developers are considering expanding the proposed capacity of the MacKenzie pipeline up to 1.9 billion cubic feet per day [**31**]. Part of the pipeline's capacity is expected to provide energy for Canadian tar sands production in Alberta, which requires about 600 cubic feet to produce each barrel of tar-sand oil [**32**]. Whether all the proposed tar sands projects will come to fruition is now under question because of the Canadian ratification of the Kyoto Treaty on December 10, 2002 [**33**].

Canadians are also considering unconventional gas resources as a supplement for conventional natural gas. The two principal unconventional gas resources being examined are coalbed methane and gas hydrates. Coalbed methane is attractive because the gas resources are estimated to be quite high, amounting to as much as 135 trillion cubic feet in Alberta alone [**34**]. The actual resource is still highly speculative, however, because there is currently no coalbed methane production in either Alberta or British Columbia, where the majority of Canada's coalbed methane resources are located. The current lack of coalbed methane production reflects both the low historic cost for developing WCSB conventional gas resources and unresolved issues about the ownership of mineral rights.

The other potential source of unconventional gas supply is natural gas hydrates, which consist of methane molecules locked in water crystals. The formation of gas hydrates occurs under low temperatures and/or high pressures. Gas hydrate deposits are found offshore in

[5]Composed of 18 trillion cubic feet in the Scotian Shelf and 45 trillion cubic feet in the Grand Banks/Labrador areas.

deepwater sediments and onshore in the Arctic permafrost [*35*]. Two test wells have been drilled in the MacKenzie Delta region of Canada. The second well, drilled in 2002, underwent a brief gas production test, which apparently gave encouraging results. Even if gas hydrate production is found to be both feasible and profitable, however, development of Canadian resources would require the construction of a gas pipeline from the Canadian Arctic to the southern gas markets.[6]

Mexico

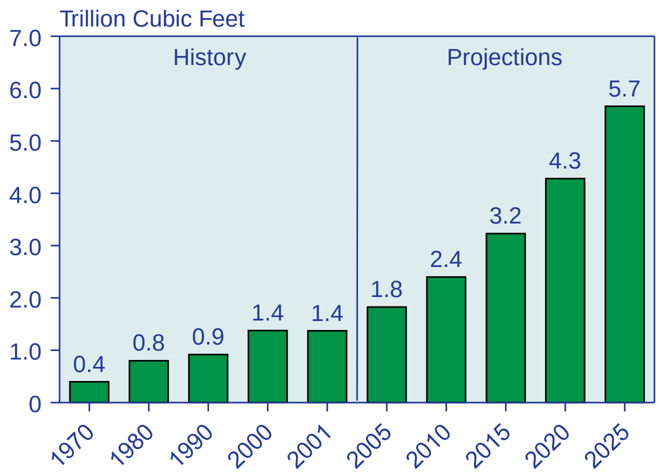
Natural gas consumption in Mexico has grown steadily over the past decade, from 0.9 trillion cubic feet in 1990 to 1.4 trillion cubic feet in 2001. For most of the decade, consumption has outpaced production, with the difference being supplied by imports from the United States. The Mexican government expects natural gas consumption to be double its 2000 levels by 2010. In the *IEO2003* reference case, strong growth is expected to continue throughout the forecast period, with consumption of natural gas projected to increase at an average annual rate of 6.1 percent per year between 2001 and 2025, reaching 5.7 trillion cubic feet in 2025 (Figure 48).

Much of the projected increase in Mexico's gas demand is expected to be for the industrial sector and for electricity generation. Residential and commercial consumption of natural gas is also expected to increase as a result of the 1995 privatization of the transmission and distribution sector that has brought natural gas distribution systems into numerous cities that before had either limited or no access to natural gas. While Mexico is currently satisfying approximately 10 percent of its demand with imports, the government anticipates that, even if production grows at an average annual rate of 9 percent, imports in 2010 will account for closer to 20 percent of total consumption.

The Mexican government's main concern about increasing imports is price, because domestically produced natural gas is significantly less expensive than imports. The availability of pipeline capacity for imports from the United States, at least in the near term, is not a major issue. There are currently 12 pipeline interconnects between Mexico and the United States, most capable of bidirectional flow. The total estimated capacity is approximately 2 billion cubic feet per day, giving an annual capacity well in excess of the 268 billion cubic feet exported to Mexico in 2002 [*36*]. Pipeline imports could increase more than fivefold before reaching capacity constraints. In addition to pipeline imports, LNG is expected to meet some of Mexico's growing demand. Several LNG receiving facilities have been proposed on both the eastern and western coasts. Although local opposition has hindered development of facilities in Baja California, it is expected that a suitable Baja location will eventually be agreed upon. Plans along the east coast are further advanced. The Mexican government has issued a tender to build a regasification facility by 2006 at Altimira, with proposals due the end of April 2003. Mexico's Federal Electricity Commission has indicated that it will commit to purchase 425 million cubic feet per day of LNG imports from the facility for 15 years.

Until recently, lack of investment in exploration and development by Petroleos Mexicanos (PEMEX), the state oil and gas company, kept new discoveries, and hence production, down. In light of Mexico's expected high growth in demand, more attention is now being focused on exploration and development. In September 1999, PEMEX proposed a strategic gas program to increase both reserves and production. Referred to as PEG, the program consists of 22 projects, all initiated in 2001, with an expected cumulative capital expenditure between 2001 and 2009 of $8.1 billion. In 2001 $1.6 billion was spent, funding the largest seismic and drilling activity in Mexico since the 1980s. Seven new fields were discovered, six offshore and one onshore, and 1.8 trillion cubic feet was added to reserves. The most promising of the new fields, the Lankahuasa, is located in shallow waters in the offshore Gulf of Mexico and may contain up to 1 trillion cubic feet of reserves. Another promising discovery is the Playuela area of the Veracruz basin, which has reactivated this mature gas-producing basin.

Figure 48. Natural Gas Consumption in Mexico, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

[6]The *IEO2003* projections for Canadian gas supplies do not include any contribution from gas hydrates.

PEMEX's goals for the next 5 to 10 years include exploration in new areas, particularly nonassociated basins[7] and the deepwater Gulf of Mexico[8]; reduction of finding and production costs; application of new technology in mature fields; strengthening the capabilities of technical personnel; and increasing foreign involvement. Two challenges that could slow the progress of the ambitious PEMEX plan are lack of autonomy in decisionmaking and the need to negotiate budgets with the government.

The PEMEX business plan is expected to increase production significantly, even without foreign involvement, but its efforts alone will not be sufficient to achieve the Fox Administration's goal of eliminating imports by 2010. Because it lacks the financial resources to develop the country's reserves fully on its own, the government feels that it is imperative to open the natural gas production sector to private investment. At present, private companies can provide services to PEMEX but are prohibited by the constitution from holding any share of ownership in any of Mexico's natural resources. A new contractual arrangement known as the Multiple Service Contract (MSC) has been developed by PEMEX to replace the current arrangement with contractors providing oil and gas related services. The MSC is considered to be a key element for future development. Although PEMEX will maintain strict control over exploration and production in accordance with the Mexican constitution, the new arrangement has been designed to open new opportunities and investment areas in the natural gas industry and to make participation more attractive to investors. It is hoped that the new MSC will attract sufficient foreign investment to supplement PEMEX's to the point that enough gas can be produced to satisfy demand by 2010. The initial emphasis will be on getting contracts in place for development efforts in the Burgos Basin[9] in northeastern Mexico, where PEMEX feels the largest production increase could be achieved.

The Fox Administration's immediate goal—to double production in the Burgos Basin from 1 to 2 billion cubic feet per day within the next 3 years—depends on the acceptance of the MSC. There is still resistance within Mexico on constitutional grounds, however, and lawyers continue to evaluate the issue. In addition, PEMEX labor unions have strongly opposed foreign involvement in the past and will most likely continue to do so. Although significant interest has been generated among investors, many remain skeptical as to its true benefits. Features that PEMEX feels will be attractive to contractors include PEMEX's commitment to produce at least 1 billion cubic feet per day from MSCs by 2007, its guarantee that all work under the contracts will be performed in areas with certified gas reserves, the length of the contracts (20 or so years, compared with the current 1 to 2 years), and unit pricing for work units performed that will reward efficiency regardless of production.

The primary disadvantage of the MSC for potential investors is that PEMEX will retain ownership of all resources and of all works performed. President Vicente Fox has had difficulty in his attempts to restructure Mexico's energy markets since he took office on December 1, 2000, because his party lacks a majority in both of the Mexican government's legislative bodies. Consequently, he has narrowed his immediate focus to one primary area, that of opening up exploration and development of nonassociated gas to private investment. PEMEX will initially offer eight blocks in the Burgos Basin for exploration and development through the MSC. The blocks contain proven reserves of 800 billion cubic feet and potential reserves of 3 to 4 trillion cubic feet. It is anticipated that the contracts will be awarded by September 2003 [***37***].

Although Mexico is making progress with efforts to open its upstream natural gas market, the lack of emphasis in the past has left the country unable to develop its resources fast enough to keep pace with the rapid growth in demand that is anticipated, at least in the near term. Mexico is thus expected to be a net importer of natural gas from the United States at least through 2015. If the government's goal of infrastructure development along with the development of additional sources of supply, such as LNG, is met, then after 2015 the country could become a net exporter. Mexico is expected to become a net exporter to the United States after 2019, and its net exports to the United States are projected to reach 0.7 trillion cubic feet per year by 2025 [***38***].

Western Europe

Natural gas remains the fastest growing fuel source in Western Europe, in spite of dwindling indigenous supplies. In the *IEO2003* reference case, Western Europe's natural gas consumption is projected to almost double over the forecast period, growing at an average annual rate of 2.4 percent, from 14.8 trillion cubic feet in 2001 to 25.9 trillion cubic feet by 2025 (Figure 49). Such growth would mean increased dependence on imports to satisfy requirements for natural gas. By one recent estimate, Western Europe's import dependence for natural gas is projected to reach 60 percent by 2020 [***39***]. With the exception of small quantities exported by France, Germany, and Norway to Eastern Europe, all Western European production is consumed in the region.

[7] Most of Mexico's reserves lie in the south and are associated with oil production. Because sufficient infrastructure to move the gas to major consuming centers in the north is lacking, a significant amount of natural gas is flared.

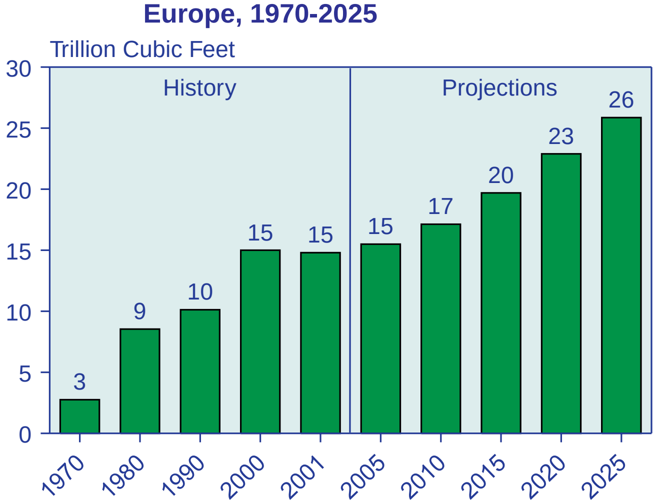
[8] Most offshore production is currently from very shallow wells.

[9] The Burgos Basin currently accounts for close to 25 percent of Mexico's production. In production since 1945, it is both the only major field in northern Mexico and the only major field producing nonassociated gas.

Most of the region's resources are concentrated in the United Kingdom, the Netherlands, and Norway. All three countries currently produce more than they consume and export the balance. Of the other Western European countries, only Denmark produced more than it consumed in 2001, exporting the balance to Germany and Sweden; and only Austria, Italy, and Germany produced more than 20 percent of what they consumed. France, the fifth largest natural gas consumer in Western Europe in 2001, produced less than 5 percent of what it consumed. Currently, the primary sources for imports of natural gas to Western Europe are Russia and Algeria for pipeline imports, as well as numerous sources, including Algeria, for LNG. France, Spain, and Italy are Europe's biggest importers of LNG, supported by exports from (in order of volume in 2001) Algeria, Nigeria, Qatar, Oman, Libya, Trinidad and Tobago, the United Arab Emirates, and others.

The United Kingdom is at present Western Europe's largest producer and second largest consumer of natural gas. For the past several years it has been a net exporter of natural gas, sending supplies to the Netherlands, Ireland, Germany, France, and Belgium in 2001 [***40***]. The United Kingdom is also Western Europe's oldest gas market, with many large, older gas fields that are or will soon be in decline. As a result, no significant growth in production is expected without new finds. With the *IEO2003* projecting gas consumption in the United Kingdom to grow from 3.3 trillion cubic feet in 2001 to 5.0 trillion cubic feet in 2025, other sources of natural gas will be needed.

Figure 49. Natural Gas Consumption in Western Europe, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

Centrica, a major UK energy supplier, already has entered into import agreements to start in 2005 with Statoil of Norway and Gasunie of the Netherlands. Arrangements have also been made with ExxonMobil for LNG from Qatar to begin flowing to the United Kingdom by 2007. Plans for new import pipelines are under consideration, with the Netherlands proposing a pipeline traversing the North Sea and Marathon and Statoil both proposing pipelines to bring gas from the North Sea (and potentially the large Norwegian Ormen Lange[10] field) to the United Kingdom. All three proposals would bring gas to Bacton, the delivery point for gas from Zeebruge, Belgium via the Interconnector pipeline, which is one of two currently existing pipelines used to import gas into the United Kingdom. The other is the Vesterland (previously Frigg) pipeline from Norway, Western Europe's second largest producer, which delivers gas to St. Fergus, Scotland. Plans have been announced to add compression that will almost triple the capacity of the Interconnector by 2005.

In addition to proposed international pipelines, the United Kingdom has several domestic pipelines that deliver gas from its own North Sea fields with spare capacity that could easily be linked to Norwegian offshore fields. Norway exports a significant amount of natural gas via pipeline and is also entering the LNG market. Europe's largest liquefaction plant is being built to process gas from the Snohvit and other fields in the Barents Sea for the international Snohvit Group, a consortium of oil companies that includes the Norwegian Statoil ASA, Norsk Hydro, and French TotalFinaElf S.A. The plant is expected to go into production by 2006 [***41***].

The largest supplier of natural gas imports to Western Europe is Russia, and those imports continue to grow. In the first 7 months of 2002, Western European imports of Russian gas increased by 5.4 percent over the same period in 2001 [***42***]. Russia has plans to increase its presence in Western European markets by building a pipeline that would bypass Ukraine and Poland (to avoid high transport fees and unauthorized diversion of gas) and initially transport gas from the Yamal Peninsula in Western Siberia to Finland, Sweden, and Denmark. The intention is to extend the pipeline subsequently to the Netherlands via Germany and then along the floor of the North Sea to the United Kingdom [***43***].

Natural gas will continue to flow to Western European markets through Ukraine, but Ukraine's aging pipeline system has deteriorated to the point that it is operating at only 50 percent of capacity. Steps are being taken to bolster Ukraine's transmission system. In early October 2002, the Russian and Ukrainian Prime Ministers took initial steps toward setting up an international consortium to manage and develop Ukraine's natural gas transmission system for a 30-year period. Several key

[10] Ormen Lange is the second largest natural gas field discovered to date in Norwegian waters.

issues, such as how shares in the venture should be distributed, remain to be resolved, but if the proposed upgrading of the system occurs, it will allow a significant increase in Russia's export capacity to Western Europe [*44*]. Western Europe also imports gas from other former Soviet Republics, notably, Turkmenistan, Kazakhstan, and Uzbekistan.

Another important source of natural gas supply for Western Europe is North Africa, and transport capacity between Europe and North Africa is being increased. North Africa (primarily Algeria) is Western Europe's second largest supplier, delivering supplies via pipeline to Italy, Spain, and Portugal and by LNG tanker to France, Spain, Italy, Belgium, Greece, and Portugal. Sonatrach, Algeria's national gas company, has an interest in a proposed LNG regasification terminal in Spain and is involved in a new venture with Gaz de France to market Algerian gas in Europe. A feasibility study has been completed for a pipeline to link Algeria with Spain, and construction is scheduled to begin in 2003. The pipeline is being constructed as a joint venture between Sonatrach and several leading European energy groups, including Cepsa, BP, Endesea, ENI, Gaz de France, and TotalFinaElf [*45*]. Algeria is increasing its exploration activities and encouraging foreign investment in the further development of its natural gas transmission and export activities. Egypt is also expected to become a supplier of gas to Western Europe [*46*].

Supplies of natural gas from Iran could also make their way to Western Europe. Iran has recently completed a pipeline link to Turkey, which it hopes is the first step toward providing supplies to Europe. The International Energy Agency, in its *World Energy Outlook 2002*, indicates that Iran, with its abundant gas supplies, is likely to become a major European gas supplier in the future [*47*]. Other options for moving Iranian gas to Europe are LNG by tanker and a pipeline through Armenia to Georgia and then on to Ukraine for ultimate delivery to Europe. The most expeditious solution will most likely be the completion and expansion of the pipeline project currently delivering Iranian gas to Turkey [*48*].

Turkey has also expressed considerable interest in entering the Western European natural gas market. The Turkish Energy and Natural Resources Minister, Zeki Cakan, has stated that preparations have been made to export natural gas to both Eastern and Western Europe. He indicated that Turkey would be signing an agreement to supply Greece with natural gas and was prepared to export gas not only to Greece but also to Austria, Hungary and Bosnia and Herzegovina [*49*]. The Austrian energy and chemicals group OMV and Hungarian oil, gas, and petrochemicals company MOL have agreed with the energy firms Botas (of Turkey), Bulgargaz (Bulgaria), and Transgaz (Romania) to undertake a 1.5-year feasibility study for a natural gas pipeline that would link Turkey with Austria via Bulgaria, Romania, and Hungary to satisfy growing demand in Eastern and Western Europe [*50*].

The European Union (EU) has set a major goal to create a single market for all aspects of trade and commerce by 2010. Important to the achievement of that goal is the liberalization of European energy markets. Virtually all European natural gas markets were founded as nationalized industries with limited, if any, participation by private companies [*51*]. The EU's legislation has played a significant role in the domestic energy policies of member countries, providing a framework for opening up both electricity markets and natural gas markets in member nations to competition.

The EU's Natural Gas Directive, passed in June 1998, required the opening of natural gas markets. It set deadlines for members (with the exception of emerging markets in Portugal and Greece) to have arrangements in place for third-party access to gas infrastructure, with target dates for individual customers set according to consumption levels. As a result of the Directive, markets in Germany and the United Kingdom were 100 percent open by 2000. Markets in Austria, France, Greece, and Portugal were less than 40 percent open, and all other EU member countries were between 40 and 99 percent open. By 2008, the European Commission projects that natural gas markets in Austria, Italy, the Netherlands, Spain, and Sweden will also be 100 percent open. The opening of gas markets is being accompanied by major changes, with nationalized gas companies being privatized, various components of the gas supply chain being bought and sold, and companies joining together to form trading alliances. These ongoing changes will facilitate cross-border trading, making a significant contribution toward meeting Europe's growing natural gas needs.

Industrialized Asia

The three countries of industrialized Asia—Japan, Australia, and New Zealand—saw relatively strong annual growth in natural gas use from 1990 to 2001—2.5 percent per year in Australia, 2.8 percent in New Zealand, and 4.0 percent in Japan. Over the projection period, the expansion of gas consumption in Japan is expected to slow considerably, increasing by a modest 1.0 percent per year between 2001 and 2025, whereas natural gas use in Australia and New Zealand combined is projected to grow by a robust 2.7 percent per year (Figure 50). Australia has only recently begun to exploit its vast natural gas resources for domestic use and in both Australia and New Zealand strong economic growth is expected to be accompanied by increasing natural gas consumption over the forecast period.

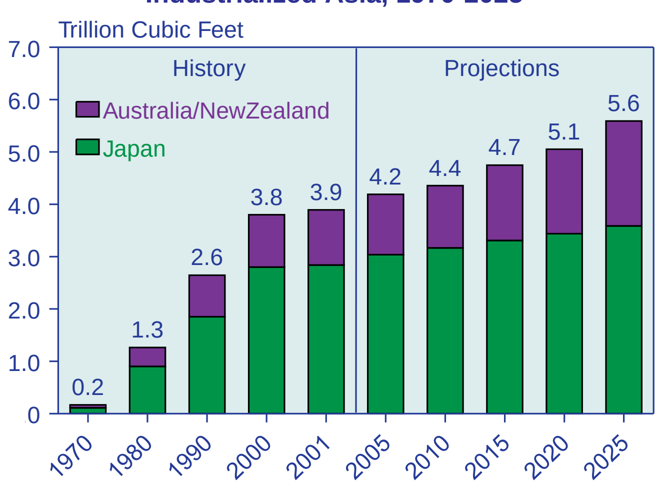
Japan

Japan is by far the largest importer of LNG in the world and, with few indigenous gas resources and limited options for pipeline imports, is expected to remain so for the foreseeable future. In 2001, Japan imported 2,615 billion cubic feet of LNG, accounting for more than one-half of the LNG traded worldwide [***52***]. In 2002, seven nuclear power plants operated by the Tokyo Electric Power Company (TEPCO) were shut down after the announcement by Japan's Nuclear and Industrial Safety Administration of suspicions that the utility had falsely reported the results of safety inspections on the reactors beginning in the mid-1980s; and by April 2003 operations had been suspended at all 17 of TEPCO's reactors, pending inspection [***53***]. Both TEPCO and the Chubu Electric Power Company—the latter with 3 nuclear reactors temporarily shut down for scheduled maintenance and another for unscheduled inspection—have been relying on natural gas (along with coal- and oil-fired generation) to meet high winter demand for electricity.

Australia

Australia's proven natural gas reserves are currently estimated at 90 trillion cubic feet, second in size only to Indonesia among the countries of the Asia/Pacific region. In spite of the country's vast resources, Australia has been fairly slow to advance the use of natural gas, which accounted for less than one-fifth of its total energy consumption in 2001. Natural gas is expected to gain market share of total energy consumption over the projection period as regulatory changes that have restructured the natural gas industry take hold and the pipeline infrastructure is expanded. The industrial sector currently is the largest consumer of natural gas in Australia, and increased use of natural gas for electricity generation is expected over the forecast horizon.

Figure 50. Natural Gas Consumption in Industrialized Asia, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

Although the Australian gas distribution network presently supplies some 3 million residential and 80,000 commercial customers, the pipeline system is fairly dispersed and fragmented and will have to be expanded to meet growing consumer demand for natural gas. In 2002, the country completed a 455-mile pipeline to Tasmania and started construction on a second hub, the so-called VicHub in Longford, Victoria [***54***]. There are currently plans to add some 5,000 miles of gas pipeline to the Australian system, including construction of a 2,000-mile pipeline to connect Australia's Queensland with Papua New Guinea.

Australia began exporting LNG in 1989 [***55***] and currently is the third largest LNG producer worldwide, after Indonesia and Malaysia. Australia plans to expand its Northwest Shelf Project by a fourth train,[11] adding 4.2 million metric tons of new capacity to the existing 8.0 million metric tons by 2004 [***56***]. The marketing company Australia Pty Ltd was able to secure a long-term contract to supply China's Guangdong regasification terminal with LNG beginning in 2005 when the terminal is scheduled for completion. Australia has also supplied substantial amounts of LNG to Japan and modest amounts on the spot market to the United States and South Korea.

New Zealand

In contrast to Australia, New Zealand has fairly modest natural gas resources. In 2003, the country's proven natural gas reserves stood at 3.1 trillion cubic feet. New Zealand's largest natural gas field, the Maui field in the Taranaki Basin, is now in decline, prompting many industry and government officials to speculate that without additional, large gas finds, New Zealand could exhaust its reserves within the next decade [***57***]. There is concern that too few resources are being invested in natural gas exploration, creating the potential for shortages in the mid-term.

Eastern Europe and the Former Soviet Union

As of January 1, 2003, the FSU held 36 percent of the world's natural gas reserves. In 2001 the FSU accounted for about 28 percent of the world's natural gas production, and 80 percent of the region's production was attributable to Russia. Russia's natural gas production in 2001 was second only to the United States, which produced 22.5 percent of the world's total compared with Russia's 22.0 percent. Growth in natural gas production and consumption among the EE/FSU countries was

[11] An LNG "train" is an independent unit for gas liquefaction. An LNG liquefaction plant comprises one or more LNG trains, and individual trains may vary in size. Significant capital costs are incurred in the construction a new LNG facility (known as a greenfield project), because infrastructure, such as ship terminals, must be built. With infrastructure already in place, it is more cost-effective to add a train to an existing LNG plant than to build a new facility.

mixed. Overall production within the FSU increased by 0.4 percent between 2000 and 2001, with decreases of 2.0 percent in Azerbaijan and 0.5 percent in Russia offset by increases of 9.1 percent in Turkmenistan, 2.3 percent in Ukraine, and 1.8 percent in Uzbekistan. While consumption dropped by 4.0 percent in Ukraine and 1.2 percent in Russia, a gain of 55.2 percent in Azerbaijan coupled with modest gains in other FSU countries overshadowed the losses, allowing the FSU to post an overall increase in consumption of 0.3 percent. This is the fourth consecutive year in which consumption in the FSU has increased, reflecting the region's continuing economic recovery.

Although unstable political and economic conditions in the early to mid-1990s led to significant declines in EE / FSU natural gas markets, conditions have improved considerably since then, and consumption continues to grow; however, the region's total consumption level of 24 trillion cubic feet in 2001 fell short of the 28 trillion cubic feet consumed in 1990. Restructuring of EE / FSU gas markets still is progressing, and the climate for foreign investment is improving. As a result, the *IEO2003* forecast projects robust growth, with consumption increasing at an average annual rate of 2.9 percent, to 46 trillion cubic feet in 2025 (Figure 51). Growth in Eastern Europe is expected to outpace growth in the FSU, with Eastern European consumption projected to grow at an average annual rate of 4.6 percent, compared with 2.6 percent for the FSU. One reason for the sizeable difference is that most of the countries in Eastern Europe have enjoyed sustained economic recovery since the early 1990s, giving them a head start over the former Soviet Republics, which have only recently begun to see sustained positive economic growth.

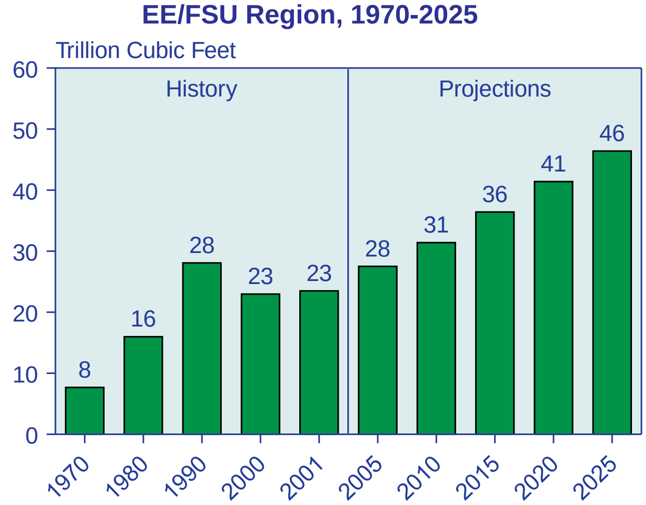
Russia dominated world trade movements in 2001, accounting for 31 percent of all natural gas pipeline exports and 23 percent of all international gas trade. The only other FSU country with any significant international trade was Turkmenistan, accounting for 1.0 percent of international pipeline movements with deliveries of 148 billion cubic feet to Iran, up sharply from 95 billion cubic feet in 2000. More than 60 percent of Russia's exports went to Western Europe. Out of a total of 2,740 billion cubic feet, 1,172 billion cubic feet went to Germany, 688 billion cubic feet to Italy, and 395 billion cubic feet to France, Russia's three main Western European markets. The remainder of Russia's exports to Western Europe went primarily to Austria, Finland, Greece, the Netherlands, and Switzerland [***58***]. Russia's exports to Western Europe in 2001 declined by 3.8 percent from 2000 levels, primarily because of lower deliveries to Italy. Italy increased imports from the Netherlands and began receiving supplies from Norway by way of the new Les Marches du Nord-Est pipeline in France.

Eastern Europe, Russia's second largest market, received 1,352 billion cubic feet and accounted for just over 30 percent of Russia's international natural gas trade. The other major recipient of Russian gas was Turkey, receiving 386 billion cubic feet or 8.6 percent of the total, up by 7.7 percent from 2000 levels [***59***]. Although Russia's exports to Eastern and Western Europe decreased between 2000 and 2001, they are now on the rise. The Interfax News Agency's October 10, 2002, *Petroleum Report* indicated that figures for the first 9 months of 2002 showed overall exports to all of Europe (including Turkey) increasing by 3.8 percent over the same period in 2001.

Notable in the EE / FSU has been the completion of major pipeline projects, the growth of international trade agreements, and progress on several infrastructure expansion proposals to facilitate international trade. Turkmenistan, Afghanistan, and Pakistan are once again discussing a $3.2 billion gas pipeline, known as the Trans-Afghanistan pipeline, to provide Turkmenistan supplies to the latter two countries. Originally planned in 1997, it was put on hold because of tensions between Afghanistan and Pakistan; however, the political climate has improved since the fall of the Taliban regime in Afghanistan and Pakistan's renunciation of the Taliban after the September 11, 2001, terrorist attacks against the United States [***60***].

Russia is exploring options to export natural gas to China, and the two countries are conducting a feasibility study that is expected to be completed by the end of June 2003. The gas would be supplied from Siberian gas fields in Irkutsk to provinces in Northeast China beginning in

Figure 51. Natural Gas Consumption in the EE/FSU Region, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

2008 [61]. South Korea has also become a party to the endeavor. Although pipeline routes through Mongolia and Manchuria have been proposed, another possibility is the development of a liquefaction facility so that the gas could be transported as LNG to markets other than China. Preliminary plans for an LNG facility call for 7 million metric tons of LNG per year for 10 years beginning in 2008 or 2010 [62]; however, such ambitious plans are unlikely to reach fruition before 2015.

In 2002, a long-term natural gas supply agreement between Norway's Statoil and Poland was reached, with Statoil agreeing to begin sending supplies in 2008 through a dedicated pipeline to be constructed from the North Sea to Poland. Plans currently are on hold because of a slowdown in the Polish economy, which has resulted in a corresponding decrease in the need for natural gas, but Statoil may increase supplies to Poland via Germany until demand picks up enough to make the pipeline viable [63]. Poland has also contracted with Russia for supplies to be delivered through the Yamal pipeline. The original agreement is for close to 9 trillion cubic feet of gas to be delivered by 2020 under a take-or-pay agreement. While Poland still wants supplies from Russia, the government is anxious to renegotiate the amount. The economic slowdown the country is experiencing, coupled with overly optimistic demand projections that the previous government used when the contract was first negotiated, has led to a substantial overcommitment on Poland's part. Poland has proposed that the amount be reduced by 50 percent, whereas Russia is proposing 30 percent [64]. Meanwhile, because producing its own gas is significantly cheaper than importing it from Russia, the Polish government has made increasing gas production a priority, stating that it hopes to increase production by 50 percent in 2007 [65].

Europe is Russia's primary export market, but Turkey has long been felt to have strong potential as an outlet for Russian gas. Currently Russia's fastest growing export market, Turkey is in a position to overtake France as Russia's third largest foreign customer. Exports to Turkey for the first 9 months of 2002 were up by 14 percent from the same period in 2001 and are expected to grow further as a result of the recent opening of the Blue Stream pipeline in October 2002. The growth will not be as strong as originally anticipated, however, because Turkey's economic problems have reduced previously estimated demand requirements [66]. Finally a reality, the Blue Stream pipeline has been in the works since Russia and Turkey signed an agreement on December 15, 1997. The project faced competition from the rival Shah-Deniz pipeline, which was proposed to bring gas from Azerbaijan's Shah-Deniz gas field to Turkey. A major find for Azerbaijan, the Shah-Deniz field is estimated to contain more than 3 trillion cubic feet of reserves. Plans to develop the field and build the pipeline to Turkey have been delayed because of both significant cost increases and the uncertainty of Turkey's future demand for gas.

Russia is looking beyond supplying Turkey with natural gas via the Blue Stream pipeline, anticipating that Turkey will become a future transit route to Europe that will bypass Ukraine, Romania, and Bulgaria. Before the Blue Stream was opened, all Russian supplies entering Turkey transited those three countries. The Blue Stream is not Russia's only attempt to bypass Ukraine in delivering natural gas to Europe. Gazprom has completed the second line of the Yamal-Europe pipeline, which transports gas from Russia's Yamal Peninsula to Germany via Belarus and Poland [67]. The first Yamal-Europe line transits Belarus and Ukraine en route to Europe.

In the past, strained relations between Russia and Ukraine regarding the transport of Russian gas led Russia to seek alternate routes to Europe. Tensions arose from Ukraine's failure to keep current in its payments for gas imported from Russia and from Russia's accusation that Ukraine was siphoning gas during transit. There is encouraging evidence that agreements have been reached and relations between the two countries are improving. According to Ukraine, Gazprom has agreed to transport about 4 trillion cubic feet of gas through Ukraine, paying part of the transit fee by providing the country with 900 billion cubic feet of gas and the rest in cash. Ukraine has also signed a contract with Russia for the transport of gas from Turkmenistan to Ukraine at a more favorable cost than that currently in effect and established an agreement that will allow Ukraine to export its own gas under Gazprom's export contracts [68]. In October 2002, Ukraine and Russia signed an agreement to set up an international consortium to refurbish and run Ukraine's aging pipeline system, which is badly in need of repair [69]. Initially consisting of Ukraine, Germany, and Russia, the consortium is open to all leading European companies.

There are still issues to be resolved before EE/FSU natural gas markets are fully developed and open, but the state of the market today is far superior to that of the early to mid-1990s, when gas markets in most EE/FSU countries were almost completely controlled by the government and efforts at privatization and foreign involvement were just beginning to develop.

A positive trend has been the improving climate for foreign investment, which is vital to the full development of the region's gas markets. An example is the readiness of major European businesses to invest in Russia's key natural gas projects, such as the development of the Barents Sea Shtokmanovaski offshore gas fields, the Yamal-Europe pipeline, and the Northern European pipeline from Vyborg in Russia through Finland and under the Baltic Sea to Europe. The Northern European

Pipeline, expected to be completed by 2009, carries a price tag of $5.7 billion [**70**]. The combined cost of all three projects is estimated to be between $25 and $30 billion, and Russia does not have the means to complete them without foreign involvement.

Interest in the projects was affirmed after a Russia-EU roundtable conference on the natural gas industry in December 2002. According to Alexi Miller, Gazprom's CEO, Gazprom has already negotiated with Shell, BP, and Centrica in the United Kingdom, Fortum in Finland, and Ruhrgas, Wintershall, and BASF in Germany, all of which expressed interest in the construction of the Northern European pipeline. The pipeline would provide Russian gas initially to Finland, Sweden, and Denmark; later to the Netherlands via Germany; and finally to the United Kingdom through a segment crossing the floor of the North Sea [**71**]. Although issues surrounding market liberalization and contract structure for gas sales are items that still need to be addressed before any final agreements can be reached, this is a positive step forward for Russia [**72**].

In addition to possible foreign investments in its projects, Gazprom has its own ambitious investment program for 2003. The Russian giant's plans are to increase total investment by 50 percent over 2000 levels, with 8 percent of the total investment earmarked for boosting extraction and transportation of natural gas and to maintain existing pipelines [**73**]. Gazprom is also relinquishing a degree of its control over the Russian gas market. While it remains Russia's largest producer, independent gas companies are slowly increasing their share of the market. As an example, Russian gas company Nortgaz, a member of Soyugaz, Russia's union of independent gas producers, doubled its 2001 production in 2002 and plans to more than triple its 2002 output by 2005. Currently Gazprom accounts for close to 90 percent of Russia's production, but it has been projected that by 2020 independent gas companies will account for about 30 percent of production. Current obstacles faced by the independents include a lack of equal access to pipelines, need for more favorable tax consideration, and difficulty in achieving profitability. Given the current market structure, their profitability is less than 0.5 percent, whereas Gazprom's profitability is between 15 and 20 percent [**74**].

Developing Asia

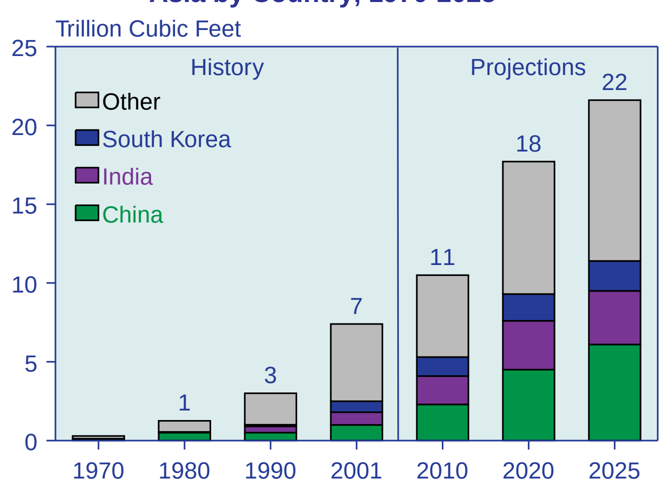
In the *IEO2003* reference case forecast, natural gas consumption is expected to expand strongly among the countries of developing Asia (Figure 52). Between 2001 and 2025, natural gas use is projected to increase by 4.5 percent per year in the region, about twice the rate projected for the countries of the industrialized world. Many countries in developing Asia are attempting to increase natural gas use, particularly for electricity generation in order to diversify electricity fuel mixes. Both China and India, two of the largest energy consumers in the region, have been making strong efforts to increase their natural gas supplies and to develop the infrastructure needed to bring gas to market. China and India together account for 55 percent of the expected regional increment in natural gas use, with projected average annual increases of 7.9 percent and 6.1 percent, respectively.

China

China's natural gas use currently accounts for a relatively small share of its total energy mix, only about 3 percent in 2001. In recent years, however, the Chinese government has made several moves toward increasing the penetration of natural gas in the country. Along with a number of aggressive moves in exploring its own natural gas resources, China has begun constructing LNG regasification terminals and several gas pipeline projects. The government has announced plans to ensure that Beijing's natural gas infrastructure is fully operational in time for it to host the 2008 Olympic summer games. In an effort to secure the Olympic games for Beijing, China committed $12 billion to reduce the pollution in the city, one facet of which will be to convert businesses from coal to natural gas [**75**]. Shanghai has announced that it will stop building coal-fired electric power plants and speed up the construction of natural-gas-fired plants [**76**].

In general, China's natural gas infrastructure is rudimentary. The largest gas pipeline distribution system is in the southwestern province of Sichuan, where some 5,400 miles of natural gas pipeline serves both industrial

Figure 52. Natural Gas Consumption in Developing Asia by Country, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

chemical plants and residential consumers. The country has plans to increase gas supplies substantially and to expand the natural gas pipeline network in the near future. The most ambitious of the planned pipelines is the 2,600-mile West-to-East pipeline currently under construction, which will connect gas fields in China's sparsely populated west to urban markets in the east, initially running from the Tarim Basin in Xinjiang Province to Shanghai and subsequently connecting to Beijing through a 200-mile link.

Several major urban centers have made plans to expand and interconnect their natural gas pipeline distribution networks. In January 2002, PetroChina signed a contract to install 470 miles of pipe that will connect 11 cities in the central provinces of Hubei, Hunan, and Sichuan [**77**]. A 470-mile pipeline that was originally supposed to be constructed by the now bankrupt Enron Corporation to link Zhongxian in southwestern China's Chongqing Municipality to central Hubei Province will be completed by PetroChina, alone or with an alternative partner [**78**]. The $600 million project will deliver 106 billion cubic feet of natural gas each year to urban centers such as Wuhan, Changsha, and Zhuzhou. Another 300-mile pipeline to connect the Changqing gas field to the Inner Mongolian city of Hohhot is currently under construction and scheduled for completion before the end of 2003 [**79**]. The $100 million project is expected to transport some 34 billion cubic feet of natural gas per year to the city.

In addition to pipeline projects that will bring Chinese natural gas to market, PetroChina is negotiating with Russia for the import of about 700 billion cubic feet of natural gas per year from Russia's Kovytka field in 2008 through an extension of the West-to-East pipeline. Talks between China and Russia about constructing a natural gas pipeline from eastern Siberia to the Bohai Bay region of northeastern China also began in mid-2002 [**80**]. A feasibility study is currently underway and scheduled for completion by June 2003 [**81**].

There are also plans to introduce facilities for LNG in China. One LNG regasification facility is already under construction at Shenzhen in Guangdong Province, and there are plans to build other plants in Fujian and Shandong. In August 2002, state-owned China National Offshore Oil Corporation (CNOOC) secured supplies for the LNG plant from Australia's Northwest Shelf with Australian marketing company Australia LNG Pty [**82**]. The 25-year contract will begin in 2005, with the completion of the Guangdong import terminal, when an initial 3.0 million metric tons of LNG will begin to be delivered, rising to 5.0 million metric tons in 2008. In September 2002, BP-Pertamina and CNOOC signed an agreement for the latter to purchase 2.6 million metric tons of LNG from Indonesia's Tangguh field located in the province of Papua, beginning in 2007 [**83**].

India

In the *IEO2003* reference case projection, natural gas use in India advances strongly between 2001 and 2025, by 6.1 percent per year. Although gas use in the country is currently only 0.8 trillion cubic feet, India has plans to increase both imports and domestic production over the next few years. By 2025, natural gas consumption is projected to reach 3.4 trillion cubic feet.

Natural gas consumption is concentrated largely in India's industrial and electricity generation sectors. Most of the future growth in natural gas demand is expected to be for power generation, as a result of government incentives to increase gas-fired generating plants along the India's coastal areas where LNG will be received [**84**]. The Indian government has ambitious plans to expand the existing 2,000 miles of natural gas distribution pipelines. Projects already underway include a 380-mile pipeline to connect Visakhapatnam to Secunderabad in the state of Andra Pradesh and a 440-mile pipeline to connect Mangalore in Karnataka to Madurai in Tamil Nadu [**85**].

With the fast-paced growth projected for natural gas demand in India, it is likely that the country will have to import substantial amounts of natural gas to meet its needs in the future. At present, India's gas imports are solely in the form of liquefied petroleum gas (LPG). There have been several proposals in recent years to develop both pipeline and LNG imports. India's political relationships with neighboring Pakistan and Bangladesh have made it difficult to advance plans for pipelines to import gas through those two countries. There have been on-again, off-again talks between India and Oman, Iran, Bangladesh, and more recently Russia, but so far they have not resulted in any firm plans to develop a natural gas import pipeline.

As a result of the difficulties in establishing the infrastructure for importing natural gas via pipeline, much of the near-term growth in India's gas imports is likely to be in the form of LNG. The country's first LNG regasification terminal, Petronet's 5 million metric ton facility at Dahej in Gugarat, is scheduled to become operational by the end of 2003. There are currently eight LNG terminal projects under various stages of completion or under consideration in India.

The Indian government is also aggressively pursuing exploration for domestic natural gas. The country currently holds proven reserves of 26 trillion cubic feet, with most resources centered in the Bombay High offshore complex, Gujarat state (both on and offshore), the Brahmaputra valley in the northeast of the country, and Andra Pradesh. In January 2003, the discovery of the largest gas field to date in India, in the Krishna Godavari Basin, was announced [**86**]. Located off the eastern coast of India, the field is estimated to contain between 5 and 7 trillion cubic feet of natural gas. The latest find has led some analysts to question the extent to which India will need to rely on imports to meet its natural gas demand.

South Korea

South Korea has had some difficulty in securing sufficient LNG supplies in 2003. State-owned Korea Gas Corporation (Kogas) opted to delay renewing or signing any new LNG contract supply agreements in 2002 as it awaited a pending government decision about restructuring the country's natural gas markets [87]. This left the company much more dependent on spot markets for its supplies. According to Cambridge Energy Research Associates, the company required an estimated 40 additional LNG spot cargoes to meet the country's natural gas demand for what has become an unusually cold winter. Unfortunately, at the same time, Japanese utilities were forced to search for their own additional spot market purchases of LNG to fuel gas-fired electric power plants that were needed as a result of Japan's nuclear power plant inspection scandal, which had closed 17 nuclear power plants by April 2003.

The result has been a very tight LNG market for South Korea in early 2003. Korea is currently wholly dependent upon LNG imports for its natural gas supplies. The country is second only to Japan as an LNG importer worldwide. South Korea has contracts to purchase LNG from a wide range of countries, including Indonesia, Malaysia, and Qatar, with smaller amounts from Brunei and Oman [88]. In January 2003, Kogas signed a 7-year purchase agreement with Australia's North West Shelf LNG for 500,000 metric tons of LNG per year, starting in late 2003 [89]. Natural gas demand in South Korea has been increasing steadily since the country's recovery from the Asian economic crisis of 1998, and natural gas use is expected to increase by a robust 3.9 percent per year over the 2001-2025 forecast period.

Other Developing Asia

Indonesia and Malaysia are the largest natural gas producers in developing Asia. They account for a substantial amount of Asia's gas exports, both by way of pipeline (to Singapore) and in liquefied form (to Japan, South Korea, and Taiwan). In 2002, Brunei and Australia were the only other Asian gas producers that exported natural gas, both in LNG form.

Natural gas is becoming an increasingly important export commodity for Indonesia, which is now the world's largest LNG exporter, accounting for about one-fifth of the world export market in 2001 [90]. With an estimated 92.5 trillion cubic feet in estimated proven gas reserves, Indonesia possesses ample resources to support domestic markets and exports [91]. LNG is processed at the country's two liquefaction plants, PT Arun LNG at Lhokseumaw in Aceh and Bongtang LNG in East Kalimantan. A third plant is being developed by BP at Tangguh to supply China with LNG for its Fujian regasification terminal beginning in 2007 [92]. There have been problems associated with the Aceh facility; an insurgency group seeking independence for the island launched a series of attacks in 2001 that caused operator ExxonMobil to suspend operations for 3 months. The bombing of a night club frequented by western tourists in Bali in 2002 may also discourage foreign companies from investing in the Indonesian energy sector in the short term.

Indonesia has recognized the need to expand its domestic distribution systems for natural gas in order to fuel gas-fired electric power generation in a country where electricity demand is rapidly increasing. Between 1995 and 2000, net electricity consumption increased by a robust 10.3 percent per year in Indonesia, even with the economic slowdown that occurred during the 1997-1998 Asian financial crisis, ultimately bringing widespread social unrest that resulted in the ouster of President Suharto in May 1998 [93]. The state-owned gas distribution company, Perum Gas Negara (PGN), currently operates around 2,800 miles of natural gas pipeline throughout Indonesia, with another 1,100 miles of pipeline currently under construction [94]. PGN also has plans to build four new pipelines before 2007, adding 1,600 miles of new pipe in order to better integrate the national gas distribution system and make it easier to deliver gas supplies to consumers throughout the country.

In addition to the domestic expansion of its natural gas pipeline system, Indonesia is planning to increase its export capabilities. PGN has begun work on a 400-mile pipeline that would connect Sumatra with Singapore [95]. State-owned oil and gas company Pertamina expects to start delivering Sumatran natural gas to Singapore beginning in early 2005. Indonesia already provides Singapore with natural gas from its Natuna Sea field. There have also been discussions about constructing an ASEAN-wide natural gas pipeline system (which may begin on a fairly small scale), linking major gas producers Malaysia and Indonesia to Singapore [96]. So far, however, there are no concrete proposals in place to implement the scheme.

Like Indonesia, Malaysia is endowed with substantial proven natural gas reserves. As of January 1, 2003, Malaysia's reserves were estimated to be 75 trillion cubic feet [97]. The country produced 1.5 trillion cubic feet of gas in 2000, half of which it consumed for domestic markets and half for export. Also like Indonesia, Malaysia is a major exporter of LNG. In 2001, Malaysia alone accounted for 15 percent of the total world trade in LNG, exporting to Japan, South Korea, and Taiwan. There are currently some limited pipeline exports to Singapore as well.

In the eighth Malaysia National Plan, the government pledged to invest some $8.2 billion between 2001 and 2005 to develop the country's natural gas reserves to meet growing demand [98]. There are also efforts underway to enhance Malaysia's domestic and international gas distribution systems. A strong proponent of the proposed trans-ASEAN gas pipeline, Malaysia is working to establish a gas link with Thailand that would bring natural gas from the Malaysian-Thai Joint Development Area in the Gulf of Thailand into Malaysia for the first 5 years of operation and after that into Thailand as well [99]. The proposed pipeline has faced numerous delays because of concerns from environmental groups and local communities that would be affected. The project still faces several legal and regulatory challenges before construction can begin, but developers hope it can be completed by the end of 2005.

Malaysia currently consumes about one-half of its total natural gas production. More than three-quarters of the gas consumed in Malaysia is for electricity generation, but with industrial sector gas demand poised to increase strongly over the projection period, that share is expected to decline somewhat [100]. Malaysia is also one of the few countries in a position to diversify its electricity fuel mix by increasing generating fuels other than natural gas. The government is promoting the development of both coal-fired and hydroelectric capacity and is introducing incentives to increase the use of wind, solar, and mini-hydroelectricity. The electricity supplier Tenaga Nasional Berhad has also begun to use a blend of diesel fuel and palm oil at some electric power plants in order to help the government support Malaysia's palm oil industry, as well as to improve its fuel diversity. All these measures will lessen Malaysia's reliance on natural gas in the power sector.

Natural gas consumption in Thailand has tripled since 1990. Demand for natural gas increased even during the Asian economic crisis of 1997-1998, when demand for other fuels declined. The country has strongly expanded the use of gas in its electric power sector, which presently accounts for most of Thailand's demand, with the rest consumed in the industrial sector [101].

Proven natural gas reserves have grown steadily in Thailand with aggressive investment in the gas sector. In 1990, Thailand reported gas reserves of 6.9 trillion cubic feet; as of January 1, 2003, reserves had grown to 13.3 trillion cubic feet [102]. As a result, the country can currently meet most of its demand with domestic resources, but it is already securing imports of natural gas to meet the rapidly expanding market. Thailand imports a modest amount of natural gas from Myanmar through the Yadana-Ratchaburi pipeline, about 55 billion cubic feet of the 192 billion cubic feet originally contracted for by the state-owned Petroleum Authority of Thailand [103]. The company was forced to renegotiate the supply contract when the Thai currency collapsed in 2000, delaying the commissioning of the Ratchaburi gas-fired power plant.

Taiwan is another developing Asian country that has seen strong growth in natural gas consumption over the past decade, from 80 billion cubic feet in 1990 to 234 billion cubic feet in 2001. Much of the increment in natural gas demand has been to fuel electricity generation. The government has encouraged the development of LNG-fired power plants, and as a result the power sector now accounts for nearly three-fourths of total natural gas consumption in Taiwan.

With fairly modest natural gas reserves, estimated as 2.7 trillion cubic feet in 2003, Taiwan has been importing LNG since 1990 in order to meet demand [104]. LNG supplies are currently provided by long-term contract agreements with Indonesia and Malaysia. There are also plans by Tuntex Gas Corporation to procure supplies from Australia's Northwest Shelf Gas Project to supply its new regasification terminal in Taoyuan County [105]. Another potential source of LNG supplies for Taiwan may come from Russia's Sakhalin-2 project. Royal Dutch/Shell announced in 2003 that it was hoping to provide state-owned Taiwan Power with 1.7 million metric tons of LNG per year for a 25-year period beginning in 2008, pending construction of an LNG receiving terminal that is part of the tender [106]. Indonesia's Pertamina is competing with Royal Dutch/Shell for the contract.

Middle East

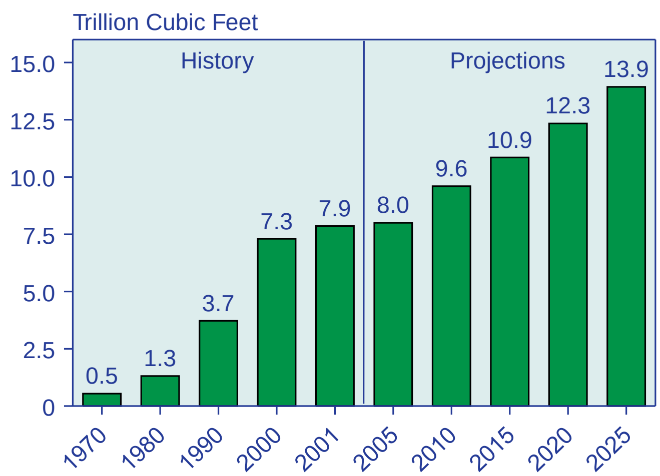
Natural gas consumption in the Middle East rose sharply in the 1990s, from 3.7 trillion cubic feet in 1990 to 7.9 trillion cubic feet in 2001 (Figure 53), and is expected to increase to 13.9 trillion cubic feet in 2025, at an annual average growth rate of 2.4 percent. Oil-exporting countries in the Middle East are seeking to expand natural gas use domestically so that as much oil as possible can be exported. Saudi Arabia, for one, has been trying to spur natural gas development for the past several years through its strategic gas initiative (see box on page 66).

Middle East countries are also planning to expand natural gas exports from the region. Although natural gas reserves in the Middle East are slightly higher than in the EE/FSU (see Figure 44), gas production lags far behind that of the EE/FSU region. In 2001, gas production in the Middle East totaled 8.3 trillion cubic feet, less than one-third of EE/FSU production. In contrast to the FSU, the Middle East has few pipelines. Nearly all natural gas exports from the Middle East are in the form of LNG. Countries in the Middle East are planning to increase LNG exports and also are exploring several pipeline options to increase export capability.

Turkey recently announced plans for a pipeline connection to Greece. Although the current proposal is modest, at 0.02 trillion cubic feet per year initially, it represents a first step for pipeline natural gas from the Middle East to reach the European pipeline network. The pipeline's overall capacity may be much higher, which would allow for additional throughput should plans advance for further connections to Europe via Italy or the Balkans [***107***]. Turkey's state-owned gas company, Botas, has also signed a separate agreement with the national gas companies of Bulgaria, Romania, Hungary, and Austria for a feasibility study on a gas pipeline that could bring Caspian or Iranian gas through Turkey [***108***].

Turkey is eager to develop re-export options for natural gas, having signed several contracts for natural gas imports only to see demand growth fail to keep pace with the contracted import volumes. Turkey recently negotiated a more flexible delivery schedule with Iran. Shipments will start at 0.07 trillion cubic feet in 2003 and rise by 0.04 trillion cubic feet per year to a plateau of 0.4 trillion cubic feet per year around 2010. The original schedule called for 0.1 trillion cubic feet per year in 2002 increasing to 0.4 trillion cubic feet per year by 2007. Russia's Gazprom has also agreed to reduce natural gas imports via the Blue Stream pipeline from 0.1 trillion cubic feet to 0.07 trillion cubic feet in 2003. Turkey is also scheduled to begin importing natural gas from Azerbaijan in 2006 under an agreement that calls for 0.07 trillion cubic feet per year initially, rising to 0.2 trillion cubic feet per year in 2009. The natural gas pipeline is to be constructed jointly and in the same corridor as the Baku-Tbilisi-Ceyhan (BTC) oil export pipeline [***109***].

Figure 53. Natural Gas Consumption in the Middle East, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

Iran has the second highest natural gas reserves in the world behind Russia but did not begin exporting natural gas until 2001. Exports were cut off for several months in 2002, when Turkey complained about poor gas quality. Flows were restarted after negotiations reduced the delivery schedule as noted above. Iran is not only interested in expanding natural gas exports through Turkey to Eastern and Western Europe but has also discussed a pipeline to India. The pipeline could be built overland but would have to transverse Pakistan, which is very difficult politically. An undersea pipeline could avoid crossing Pakistan, but it would have to be built at depths of up to 11,500 feet, much deeper than the 7,000-feet depths reached by the Blue Stream line across the Black Sea [***110***].

In addition to pipeline projects, Iran is also planning to construct LNG facilities for exporting natural gas as part of its massive South Pars development. Iran's South Pars Oil and Gas Company is seeking bids for phases 11 and 12, which involve LNG exports from a proposed 8 million metric ton plant at Assaluyeh on the Persian Gulf. South Pars development has experienced some delays, however. Phase 1, involving natural gas and condensate production, is expected to come on stream around the end of 2003. Phases 2 and 3 started producing 0.4 trillion cubic feet of natural gas per year in March 2002. Phases 4 and 5 are stated to be back on track with some 28 percent progress [***111***]. Iran is aiming to supply India with LNG but will have to compete with several other producers in what is currently a buyer's market.

Qatar has been aggressively expanding its LNG facilities. Qatar has one of the largest gas fields in the world, the North Field, situated near Iran's South Pars field, and is aiming to triple its LNG capacity to 45 million metric tons per year by 2010. Qatar has long-term contracts with buyers in Spain, Japan, and South Korea, and agreements are in place for future deliveries to India, Italy, and the United Kingdom. Qatar has also sold spot cargoes to the United States. In addition, Qatar has plans to build gas-to-liquids plants and is expected to provide the natural gas for the first long-distance pipeline project in the Gulf area, the Dolphin project [***112***]. Dolphin Energy is waiting to sign a crucial long-term sales contract with the emirate of Dubai, which is expected to cover about one-half of the initial demand. The project is expected to pump at least 0.7 trillion cubic feet per year of Qatari gas to the United Arab Emirates [***113***].

Natural gas requirements have been outstripping production in the United Arab Emirates, which has given impetus to the Dolphin project. The vast majority of Abu Dhabi's gas reserves are associated and hence constrained by oil production. In addition, rising oil field reinjection requirements and a surge in power demand is pushing up the demand for natural gas. Dubai has also

The Saudi Gas Initiative

In the late 1990s, the government of Saudi Arabia was facing budget deficits and declining revenues from oil sales, the result of a combination of relatively low oil prices and high domestic unemployment rates. The government also recognized the need to increase electricity supplies in Saudi Arabia's rapidly growing residential and industrial sectors. By one estimate, Saudi Arabia will need at least $117 billion of investment in the electricity sector alone to meet demand in the next 20 years.[a] In 1998, the Saudi crown prince held informal discussions with several international oil companies about possible investment in the kingdom of Saudi Arabia. The attending companies were invited to submit proposals for exploration and development projects, primarily in the natural gas sector, as part of a "strategic gas initiative."

The Saudi Gas Initiative (SGI) has attracted considerable interest. Indeed, it amounts to the largest integrated gas development plan anywhere in the world. Saudi government advocates of opening the upstream sector to partnerships with foreign investors believe that the SGI will lead international oil companies to invest $25 billion in the near term and possibly further direct investment of $50 billion or more over the next 25 years. Further, they estimate that every dollar invested will generate $5 to $8 of investment in other sectors of the Saudi economy,[b] and that every billion dollars of investment by foreign oil companies will create 15,000 new jobs. The companies involved in SGI apparently do not believe that the projects proposed will achieve those goals,[c] arguing that natural gas and oil development are capital-intensive, not labor-intensive ventures and so cannot be used to solve Saudi Arabia's unemployment problem.

Although Saudi Arabia holds the fourth largest reserves of natural gas in the world, at 224 trillion cubic feet (of which 88 trillion cubic feet is nonassociated), the country has been slow to develop its natural gas resources. Saudi Arabia's current natural gas production is around 5.3 billion cubic feet per day.[d] The government has estimated that domestic consumption could increase by 12 to 14 billion cubic feet per day over the next 20 years or so, assuming that necessary investment will be made to convert existing oil-powered utilities to run on cheaper natural gas and to meet future demand for new capacity with more efficient gas-fired technologies.

The decision to open upstream natural gas development to foreign companies, as proposed in the SGI, has not been universally popular in Saudi Arabia and is particularly unpopular with the state-owned Saudi Aramco, which for the past 30 years has held a monopoly on the development of hydrocarbons in Saudi Arabia. Saudi Aramco believes it has proved its technical and managerial capabilities to explore and develop its natural gas reserves without foreign intervention. In 2002, for example, the company successfully developed the Haradh and Hawiyah gas projects, including the world's largest plant for processing nonassociated natural gas, as part of the Master Gas System (which predated the SGI).

From the beginning, the companies that were invited in 1998 to participate in the SGI had some difficulty obtaining the detailed information they needed to draw up proposals. In 2000, in an effort to speed up the process, the Saudi government created a new body, the Supreme Council for Petroleum and Mineral Affairs (SCPMA), to review SGI proposals and increase cooperation between the various Saudi ministries involved. The SCPMA was also given direct control over Saudi Aramco, an important aspect of the new body's function.

The SCPMA has indicated a preference for integrated natural gas projects that cover upstream nonassociated gas exploration and development, gas processing and transportation, and ethane and natural gas liquid extraction and fractionation facilities, as well as downstream power, water desalination, and petrochemical plants.[e] SCPMA has also stated clearly that Saudi Aramco will play an active role as a partner in any deal signed with foreign countries participating in the SGI. Other Saudi government bodies, such as the Electricity Authority, will also be involved, as will private Saudi companies either directly or through related services.

The SGI consists of three core ventures (see map on following page):

(continued on page 67)

[a]"Energy Sector Analysis: Saudi Arabia Oil and Gas," *World Markets Analysis OnLine*, web site www.worldmarketsanalysis.com (February 24, 2003).

[b]D. Sabbagh, "Saudi Foreign Minister Sees $50B Invest in Saudi Gas by 2025," *Dow Jones Newswires Release* (June 3, 2001).

[c]D.B. Ottaway and R.G. Kaiser, "After Sept. 11, Severe Tests Loom for Relationship," *The Washington Post* (February 12, 2002), p. A01.

[d]"Gas Assumes Prominent Saudi Energy Role," *World Gas Intelligence*, Vol. 13, No. 32 (August 7, 2002).

[e]"Saudi Arabia and Eight IOCs Sign Gas Initiative Preparatory Agreements," *Middle East Economic Survey*, Vol. 44, No. 24 (June 11, 2001), p. A9.

The Saudi Gas Initiative (Continued)

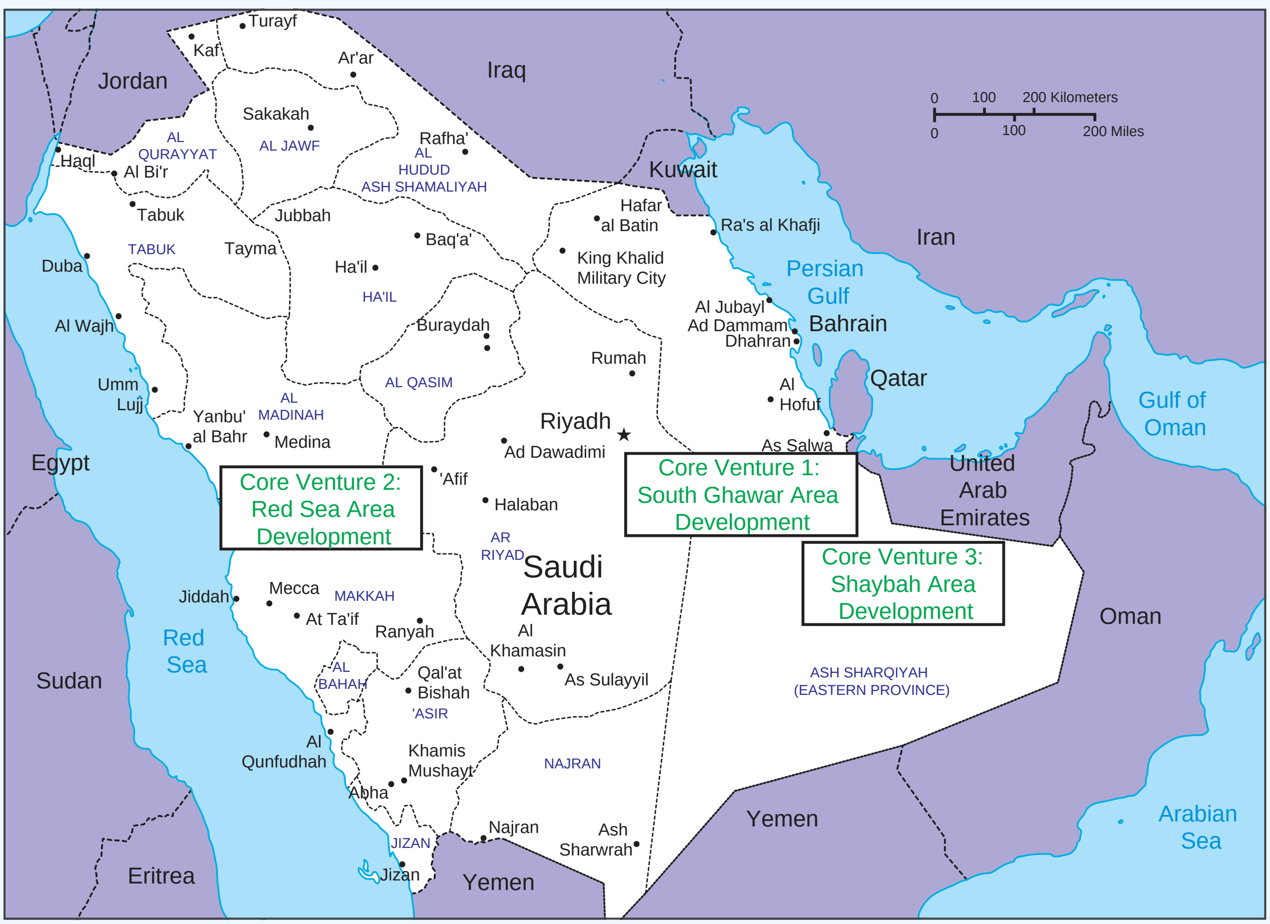
- Core Venture 1, the South Ghawar Area Development, is located in the eastern part of the kingdom, near the Persian Gulf. Natural gas would be produced from the southern part of the Ghawar oil field (the largest oil field in the world), in the Haradh and Hawiyah areas. Estimated gas reserves on offer are about 21 trillion cubic feet.[f] This venture also involves significant downstream elements, including two 2,000-megawatt power stations and desalination plants at Jubail and Yanbu that can produce 300 million gallons of desalinated water a day, and two petrochemical plants, one at Jubail fueled with ethane and a second at Yanbu fueled with mixed feedstocks, with a total capacity of 2 million metric tons of petrochemical production per year. The expected cost of Core Venture 1 is about $15 billion.

- Core Venture 2, the Red Sea Area Development, involves development of the Barqan, Umm Luj, Al Wajh gas fields in the northern Red Sea area, some of which were discovered in the late 1960s but have never been developed. With fewer proven gas reserves than Core Venture 1, the project will involve the development of pipelines to Tabuk and Yanbu, as well as construction of one power and one desalination plant. The estimated cost of Core Venture 2 is about $5 billion.

- Core Venture 3, the Shaybah Area Development, involves the development of the Kidan sour gas field near Saudi Arabia's eastern border with the United Arab Emirates, in addition to the installation of treatment and transport facilities for associated gas extracted from the Shaybah oil field, with potential reserves of 10 trillion cubic feet of gas and a production capacity of 600 million cubic feet per day. It includes the construction of a pipeline and petrochemical plant, a 1,100-megawatt power plant, and a desalination plant that can produce 75 million gallons of desalinated water a day, all to be located on the Persian Gulf coast. The estimated cost of Core Venture 3 is about $5 billion.

In January 2001, the SCPMA narrowed the list of potential SGI participants to eight. The companies

(continued on page 68)



[f]"Saudi Gas Opening Not Closed Yet," *World Gas Intelligence*, Vol. 13, No. 38 (September 18, 2002), p. 1.

The Saudi Gas Initiative (Continued)

were grouped into three consortia, and a timetable was set to move forward. Later in January, Saudi Aramco's data rooms in Dhahran were opened to the short-listed firms. In May 2001 the composition and leadership of the consortia for the three core ventures was announced:

- Core Venture 1: ExxonMobil (lead with 35 percent), Shell (25 percent), BP Amoco (25 percent), Phillips (15 percent)
- Core Venture 2: ExxonMobil (lead with 60 percent), Occidental and Enron[g] (40 percent split between the two)
- Core Venture 3: Shell (lead with 40 percent), TotalFinaElf (30 percent), Conoco (30 percent).

The two leading companies in the three core ventures, ExxonMobil and Shell, are familiar with the local market conditions in Saudi Arabia as a result of their long-standing downstream joint venture projects dating back to the mid-1980s.

In June 2001—in the rare presence of the ailing Saudi king and the country's crown prince and other key officials—BP Amoco, Shell, ExxonMobil, Phillips, TotalFinaElf, Marathon, Occidental, and Conoco signed memoranda of understanding (MOUs) for the first foreign investment deals in the kingdom since Saudi Arabia nationalized its oil and gas sector in 1976.

Negotiations over details of the SGI have been slow and contentious since the signing of the MOUs in 2001. The Saudis were unable to reach an agreement with the foreign oil companies on a range of important issues. Final deadlines have come and gone with no agreement in the foreseeable future, leading to speculation that all three of the core venture projects ultimately may have to be re-tendered.

The issues of contention have ranged from determining tax terms and access to upstream gas reserves to ownership of the gas liquid, the guaranteed rate of return on investment, and tariffs on water and electricity. In their submissions, the international companies had assumed that a 30-percent tax rate would apply under Saudi Arabia's new laws on foreign investment; however, Saudi Aramco, supported by the tax authorities, sees gas development as subject to petroleum tax laws dating back to the mid-1970s, implying a 20-percent royalty before cost recovery and an 85-percent tax on the remaining output.[h]

The leading companies in the three core ventures stated that they had been led to believe that they would be given direct access to some 74 trillion cubic feet of nonassociated natural gas, whereas in fact the data submitted by Saudi Aramco showed the gas reserves to be far smaller than initially believed.[i] The downstream aspects of the core ventures would become less profitable if insufficient access to gas reserves drove up the cost of feedstocks bought from Saudi Aramco. The Saudis have indicated that extra acreage would be made available if there were insufficient volumes of gas in the areas assigned to the core ventures. On the liquid ownership issue, the Saudis are adamant that any oil or gas liquid developed from the scheme must be transferred to Saudi Aramco control.

Determining the guaranteed rate of return on capital has been among the stickiest issues in the negotiations. The foreign oil companies were seeking 18 to 20 percent as a guaranteed rate of return on their investments. The Saudis initially offered 10 to 12 percent, as is the norm for similar projects in the Persian Gulf region and in Europe,[j] but have recently revised the offer to a guaranteed rate of return between 14.5 and 15.5 percent for the three core ventures. They have also presented figures for the maximum prices per gallon of water and per kilowatthour of electricity to be produced in the proposed SGI water and power projects.[k] The new figures seem to be close to those desired by the participating foreign companies.

The Saudi government has suggested that it might also reduce the foreign companies' commitment to power and water projects, as they had been demanding, because there is an urgent need to press ahead with some of those projects. The Saudi government has been approached by a number of companies—particularly in the power and water sectors—offering their services at a lower rate of return and willing to team up with Saudi private investors, as was done by the first independent power producer in Saudi Arabia, a joint venture between a Saudi private investor (Al Zamil Industrial Group) and a foreign service company (CMS Energy) that was approved 2 years ago.[l]

[g]Enron, originally named as part of Core Venture 2, pulled out with no explanation and gave up its stake. Marathon was selected to replace Enron.
[h]"Motors Still Idling at Saudi Starting Line," *Petroleum Intelligence Weekly* (January 8, 2001), p. 1.
[i]"Saudi $25bn Gas Scheme Seen Teetering on Brink," *Platts: International Gas Report* (September 13, 2002), p. 1.
[j]"Saudi Arabia, IOCs in Gas Initiative Continue Work on Response to Ministerial Committee," *Middle East Economic Survey* (October 7, 2002).
[k]"UK Daily Energy News," *World Markets Analysis OnLine*, web site www.worldmarketsanalysis.com (October 1, 2002).
[l]Personal communication with Dr. Abdulrahman Al Zamil, Member of the Shoura Council and Chairman of Al Zamil Industrial Group, December 2002.

been receiving about 0.2 trillion cubic feet of natural gas per year from Abu Dhabi since 2000 to meet soaring power demand, a figure that is expected to grow. The project is aiming for 2006 for the first gas deliveries [***114***].

Africa

Natural gas consumption in Africa is projected to increase from 2.3 trillion cubic feet in 2001 to 5.3 trillion cubic feet in 2025 (Figure 54), at an average annual growth rate of 3.6 percent. Africa is a major exporter of natural gas. In 2001, Africa accounted for about 12 percent of the natural gas traded in the world. More than 85 percent of Africa's gas exports went to Western Europe. Natural gas exports from Africa are expected to increase through the forecast period, with Western Europe continuing to be the main recipient. Several pipeline and LNG projects are aimed at supplying the rising demand for natural gas in Europe.

Algeria is the second largest LNG producer in the world and also has significant pipeline exports. Algeria is hoping to add a new 4 million metric ton LNG train as part of the development of its Gassi Touil project, but the inability to pass a new hydrocarbons law, a dispute with European Union competition authorities over resale restrictions, and stiff competition from a growing list of LNG suppliers has slowed the process [***115***]. Algeria has expressed interest in expanding sales of LNG to the United States, which amounted to 0.06 trillion cubic feet in 2001, as a means of diversifying its customer base. Algerian Minister of Energy Chakib Khelil expressed concern, however, that a U.S. regulatory requirement for third-party access to any new receiving terminals may impede construction of new import terminals [***116***].

In 2001, Algeria exported 0.8 trillion cubic feet of natural gas via the Transmed (Enrico Mattei) pipeline through Tunisia to Italy. Sonatrach, the Algerian state-owned company, plans to boost the capacity of the line to 1.1 trillion cubic feet per year [***117***]. Algeria and Italy also agreed in late 2002 to explore the feasibility of another pipeline connection through Sardinia and Corsica. The new pipeline is expected to add export capability of 0.3 to 0.4 trillion cubic feet per year and would probably take 4 to 5 years to complete [***118***]. In addition, a feasibility study was done on a direct line from Algeria to Spain. Each of the seven European partners in the Medgaz pipeline project is understood to have signed or be close to signing a letter of intent to purchase 0.04 trillion cubic feet per year from the pipeline. Initial capacity is planned at 0.3 trillion cubic feet per year, with the possibility of increasing it to 0.6 trillion cubic feet per year [***119***]. Compressors are being added to the existing pipeline through Morocco to raise capacity to 0.5 trillion cubic feet per year by 2004, from 0.3 trillion cubic feet per year in 2002 [***120***].

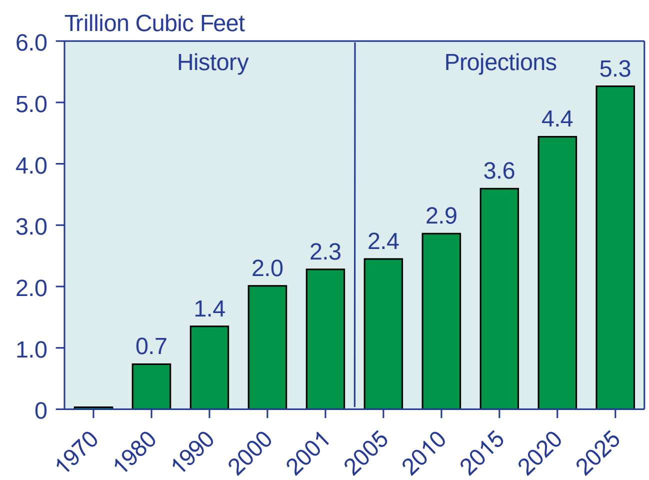
Egyptian LNG (ELNG) is moving ahead with plans to develop several trains at Idku. The entire output of the first train has been sold to Gaz de France under a 20-year agreement. The first train is already under construction, and production is expected to begin in the third quarter of 2005. The site can accommodate up to five trains, and an innovative commercial structure allows third parties to invest in future LNG production trains at the site. A second train is in the planning stages [***121***].

Spanish utility Union Fenosa hopes to start deliveries from its 5.0 million metric tons per year LNG train at Damietta, Egypt, in 2004, just a few months before the first output from the LNG facilities at Idku. Adequate gas supply has been a concern, but a discovery by Italy's ENI in late December 2002 may help to alleviate those concerns. A preliminary appraisal of the Tennin reserves came in at 0.5 to 1.1 trillion cubic feet. ENI recently purchased 50 percent of the gas business of Union Fenosa [***122***].

Libya is planning to expand its export capability by building a pipeline from Melitah on the Libyan coast to Gela in Sicily. With a capacity of 0.3 trillion cubic feet, the pipeline is part of the development of the onshore and offshore Wafa fields. It includes an offshore platform, gathering networks, and a gas treatment plant. The first gas is set to flow in 2005 [***123***].

Nigeria's natural gas reserves rank ninth in the world, but in the past more than one-half of its production has been flared due to lack of infrastructure. About 25 different gas projects are currently underway in Nigeria.

Figure 54. Natural Gas Consumption in Africa, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

Some of the projects aim to reinject the gas, but others intend to channel supplies to Nigeria's expanding LNG facilities. The current deadline to end flaring is 2008, and Nigerian president Obasanjo has indicated a desire to move the deadline forward to 2004 [**124**].

Nigeria began exporting LNG from its third train on December 18, 2002, and signed a $1.06 billion loan on December 19 that will provide some of the funding for the fourth and fifth trains. Spain's Gas Natural (GN) and Portugal's Transgas have contracted for the supply from the third train [**125**]. Trains 4 and 5 are targeted for completion at the end of 2005. Nigeria LNG has four sales agreements and two memoranda of understanding covering the output from trains 4 and 5, all with European companies. Feedstock gas for the new trains is expected to be 100 percent associated gas, with nonassociated gas as a backup. The first two trains run up to 40 percent associated gas. A final investment decision on train 6 is expected in September 2003 [**126**].

Nigeria is also planning an export pipeline into Ghana, Togo, and Benin. The presidents of the four countries involved are expected to sign an intergovernmental treaty providing a common legal framework for the line, followed by the establishment of the West African Pipeline Company (Wapco). The project developers hope to begin pumping gas in 2005, with initial flow rates of about 0.07 trillion cubic feet per year [**127**]. Also under consideration is a pipeline north from Nigeria to supply natural gas to Niger and Mali, which could eventually be linked to the pipeline network in North Africa and provide pipeline gas to Europe [**128**].

Central and South America

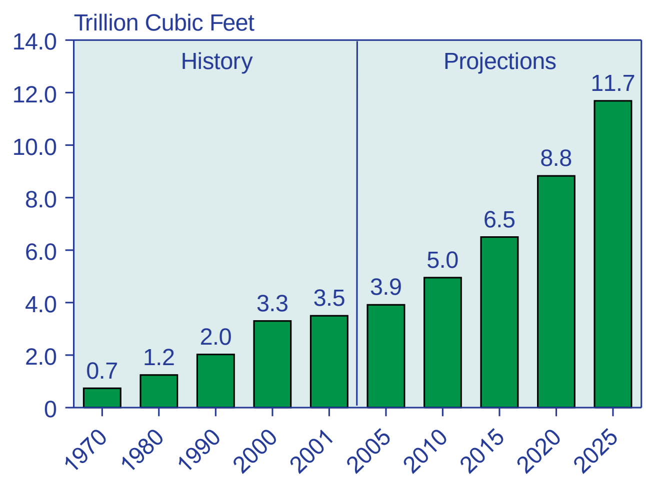
Although natural gas markets in Central and South America accounted for only 3.9 percent of the world's natural gas consumption in 2001, they are growing rapidly. Consumption in the region increased by 73 percent between 1990 and 2001, and *IEO2003* projects continuing growth of 5.2 percent per year over the forecast period, to 11.7 trillion cubic feet by 2025 (Figure 55). Currently, except for LNG exported from Trinidad and Tobago, all of Central and South America's natural gas production is consumed within the region, and indigenous production is sufficient to meet current demand.

Natural gas markets are still in the early stages of development in many Central and South American countries. Exploration activities continue to yield promising discoveries, and reserves increased from 245 trillion cubic feet at the end of 2000 to 253 trillion cubic feet at the end of 2001 [**129**]. The highest concentrations of reserves are in Argentina and Bolivia in the South and Venezuela and Trinidad and Tobago in the north. Venezuela's 148 trillion cubic feet of reserves far surpasses those of any other country in the region. The second highest concentration of reserves, 28 trillion cubic feet, is in Argentina. Other countries holding notable reserves, in order of amount, are Brazil, Colombia, and Ecuador.

Natural gas production in Central and South America as a whole increased by 3.7 percent from 2000 to 2001, led by production increases in Bolivia and Brazil of 21 and 13 percent, respectively. Trinidad and Tobago was the only major producer that reported a decrease, with production declining by 0.5 percent. Consumption increased throughout the region, led by Brazil with a 19.3-percent increase, Peru with a 7.1-percent increase, and Chile with a 6.5-percent increase. The overall growth of natural gas consumption in the region was 4.1 percent. The major trade movements were from Argentina to Chile and from Bolivia to Brazil, with Argentina also exporting to Brazil and Uruguay. Central America neither produced nor consumed any natural gas.

Although the region's natural gas markets have continued to grow overall, economic and political turmoil has had an impact on energy markets. The Argentine economic crisis, which led to a 29-percent currency devaluation in January 2002, continues and, along with the downward adjustment of salaries by both the government and private industry, has destroyed consumer confidence and brought a halt to the almost steady growth in consumption the country had experienced over the past decade. Argentina's natural gas industry is entirely in the hands of the private sector, but weakening domestic demand along with the struggling economy has made the private sector hesitant to invest further until conditions stabilize. As a result, the government's plans to attract foreign investment in Argentina's natural gas sector has slowed considerably [**130**].

Figure 55. Natural Gas Consumption in Central and South America, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

In Venezuela, a political strike, led by a coalition of union and management workers at the state oil and gas company PDVSA, began in early December 2002, protesting the Chavez government's interference in PDVSA's operations. The strike has put the government's plans to develop its natural gas sector in jeopardy. While repercussions in the oil sector, which accounts for 75 percent of Venezuela's exports, are much more severe than in the natural gas sector, they will delay plans for PDVSA to join a feasibility study on the Mariscal Sucre LNG project and for the government to restructure the natural gas sector and begin exploration and production of nonassociated gas [***131***]. Venezuela opened its downstream natural gas market to foreign investment in May 1998 and opened the exploration and development of nonassociated gas to foreign investment in August 1999. The Chavez administration's goal is to increase both production and consumption of natural gas in the near term. Because of the current political turbulence, however, foreign investors have backed off, and the government's plans to develop offshore gas fields have ground to a halt [***132***].

Brazilian state oil company Petrobras has been experiencing some economic problems resulting from its take-or-pay arrangements with the Bolivian state oil and gas company, YPFB. Making up the difference between contracted amounts and what has actually been taken is expected to cost between $50 and $60 million. Petrobras is also liable for payments for unused transport capacity it has contracted for on the export pipeline. The transport capacity liability could soon become significantly worse, because the transport capacity committed to by Petrobras is set to increase by 50 percent in March 2003. Bolivian producers and the Bolivian government are also not happy with the situation. Under the terms of the contract, producers must supply any undelivered volumes at the end of the contract in 2019; as a result, Bolivian producers are receiving money that cannot be registered as profit for a future liability. The government is unhappy with the fact that it is unable to tax payments that the producers receive for unsold gas [***133***].

South America's LNG market continues to grow. Venezuela has been trying for more than 20 years to enter the LNG market. The Mariscal Sucre LNG project is the successor to the Cristobal Colon project that was begun in 1990 in the hope of building a liquefaction train and exporting LNG beginning in 1997 but, like other Venezuelan LNG projects, was abandoned. The new Mariscal Sucre project will be held by PDVSA (60 percent), Shell (30 percent), and Mitsubishi (8 percent). The remaining 2 percent will be open to private investors in Venezuela. Mariscal Sucre consists of the development of four offshore fields with proven reserves of 4 trillion cubic feet and probable reserves of 10 trillion cubic feet and subsequent construction of a liquefaction facility beginning in 2004. The government's goal is 1 billion cubic feet per day, with 300 million cubic feet destined for local markets and the remainder for export [***134***].

The Mariscal Sucre project will be in direct competition with the Trinidad and Tobago liquefaction trains. Trinidad and Tobago has been exporting LNG since the first train at Atlantic LNG's Point Fortin facility became operational in 1999. In 2001, 32 percent of Central and South America's exports were in the form of LNG from Trinidad and Tobago, with 72 percent going to the United States, 16 percent to Puerto Rico, and the remaining 12 percent to Spain. Train 2 became operational in August 2002, and train 3 is under construction and expected to become operational by the second quarter of 2003. According to Atlantic LNG, the disposition of the output of the train 2 and train 3 expansions is to be 62 percent to the Spanish conventional and power markets and 38 percent to the U.S. market, primarily to the southeast through the Elba Island terminal. A fourth train is currently under consideration, and public consultations began in September 2002 to get feedback on the proposed additional train [***135***].

Bolivia is also attempting to enter the LNG market. In December 2001, the Pacific LNG consortium entered into a 20-year agreement with Sempra Energy for 800 million cubic feet per day of LNG to be exported from Bolivia to North America to serve Mexican and U.S. markets. The agreement called for the construction of a two-train liquefaction facility on the Pacific coast of South America. An extended debate has been going on as to whether the facility will be built along the coast of Peru or the coast of Chile. While the Chilean port seems to be the most viable economically, historical hatred of Chile by the Bolivians over land disputes has made negotiations difficult. The government's reluctance to make a decision, however, could jeopardize the project; and rumors imply that the government is about to announce the choice of the Chilean port of Patillos [***136***].

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