# Worldwide Natural Gas Supply and Demand and the Outlook for Global LNG Trade

This article is adapted from testimony by Jay Hakes, Administrator of the Energy Information Administration, before the Senate Energy and Natural Resources Committee on July 23, 1997. The hearing focused on the examination of certain aspects of natural gas into the next century with special emphasis on world natural gas supply and demand to 2015.

Natural gas is a highly desirable energy source. It burns cleanly, with less pollution than other hydrocarbon fuels, and proved reserves of natural gas are immense—some 4,900 trillion cubic feet worldwide at the end of 1995, enough for about 60 years supply at current world gas production rates. However, much of the world's known natural gas reserves are inconveniently located in remote and thinly populated areas, such as Western Siberia and the Persian Gulf. The United States and Canada have been girdled with large gas pipelines that transport gas from the producing fields of Texas, Louisiana, Oklahoma, and Alberta to consuming markets in California, New England, and elsewhere. At present, however, pipeline transport is generally not an economically feasible option for transporting natural gas across oceans. Moving natural gas between continents requires an alternative approach.

Liquefied natural gas (LNG) is a proven commercial technology for transporting natural gas across oceans. The international trade in LNG is more than 30 years old. LNG is presently being exported from eight countries (Indonesia, Algeria, Malaysia, Australia, Brunei, the United Arab Emirates (UAE), the United States, and Libya) and imported into eight countries (United States, Japan, South Korea, Taiwan, Belgium, France, Spain, and Turkey) (Figure SF1). LNG trade expanded by 44 percent between 1990 and 1996, rising from 2.6 trillion cubic feet (Tcf) to 3.6 Tcf.

The countries with the largest LNG consumption are in Asia, which imported more than 2.8 Tcf of LNG in 1996 (Table SF1). Japan is by far the largest user of LNG, importing in 1996 almost two-thirds of the world's 3.6 Tcf of LNG production (Figure SF2). South Korea is a distant second with 13 percent of the total, followed by Taiwan with 3 percent. Together this region imported more than three-quarters of the total production of LNG in 1996. The needs of this region remain the focus of the story with respect to the growth potential of LNG.

Despite the success of individual LNG projects and the regional importance of LNG, overall, LNG accounts for only 5 percent of world natural gas consumption. It has had only a marginal influence on world patterns of gas consumption thus far. It is useful to start this discussion of LNG with a look at the overall market for natural gas to put the needs of potential LNG users into perspective.

## *Growing Demand for Natural Gas Is Expected Worldwide*

The role of natural gas in the world's energy supply is growing rapidly. According to the *International Energy Outlook 1997* (*IEO97*) published by the Energy Information Administration in April 1997,[1] total world natural gas demand is expected to reach 145 trillion cubic feet by 2015, an 85-percent increase over the 1995 level of 78 trillion cubic feet. The *IEO97* does not identify the LNG portion of this consumption, because the model used to generate natural gas consumption projections does not distinguish the form gas takes before it is consumed. The *BP Statistical Review of World Energy 1997* estimated that LNG represented 4.6 percent of the total world consumption of natural gas in 1996.[2] Over the next two decades, gas use is projected to rise at more than three times the rate for oil use. The growth in natural gas consumption is equivalent to more than 33 million barrels of oil per day. In comparison, oil use in 2015 is projected to be 35 million barrels per day higher than in 1995. Resource availability, cost, and environmental considerations all favor growing reliance on gas in industrial applications and electricity generation, and natural gas is replacing other fuels in residential and commercial sector uses as well.

The highest growth rates in natural gas demand are projected for the developing countries of the world, where overall demand in the *IEO97* reference case rises by 5.0 percent annually between 1995 and 2015 (Figure SF3). Developing Asia is expected to experience annual gas consumption increases of almost 8 percent. Much of this growth will fuel electricity generation in the region, but infrastructure projects are also underway for natural gas to displace polluting home heating and cooking fuels in major cities such as Bombay, Shanghai, and Beijing. These areas have limited access to gas

## Figure SF1. Major LNG Flow Routes, 1997

Source: British Petroleum Company, *BP Statistical Review of World Energy 1997*.

## Table SF1. Trade Movements 1996 - Liquefied Natural Gas
(Billion Cubic Feet)

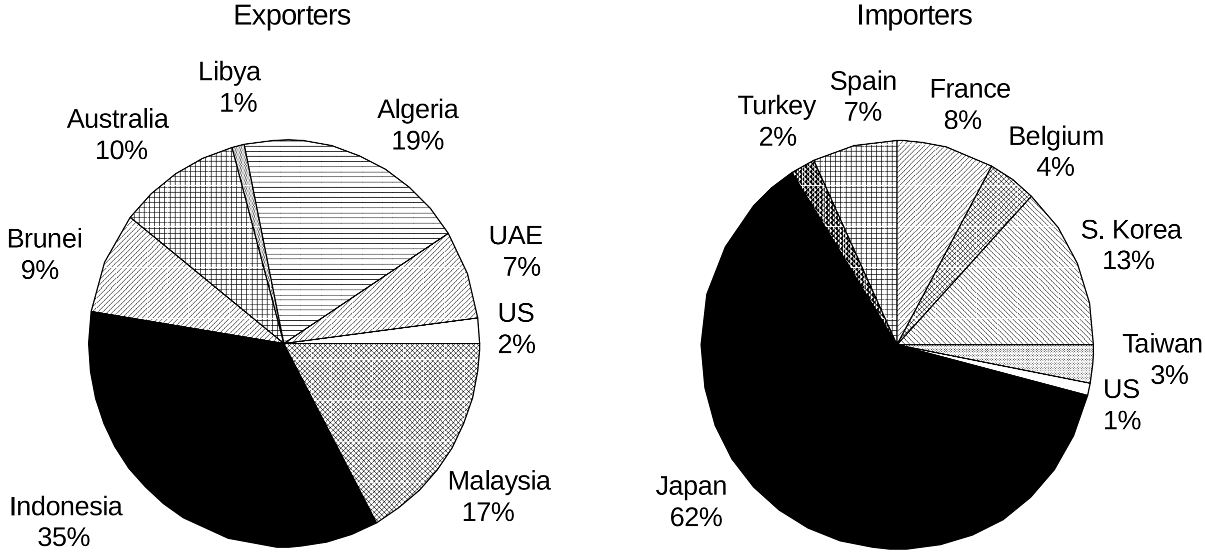
| To | From | | | | | | | | Total Imports |
|---|---|---|---|---|---|---|---|---|---|
| | USA | UAE | Algeria | Libya | Australia | Brunei | Indonesia | Malaysia | |
| **North America** | | | | | | | | | |
| USA | - | 7.1 | 35.3 | - | - | - | - | - | 42.4 |
| **Europe** | | | | | | | | | |
| Belgium | - | * | 141.3 | - | - | - | - | - | 141.3 |
| France | - | 7.1 | 268.4 | - | - | - | - | - | 275.5 |
| Spain | - | 31.8 | 169.5 | 42.4 | * | - | - | - | 243.7 |
| Turkey | - | - | 77.7 | - | 3.5 | - | - | - | 81.2 |
| **Asia Pacific** | | | | | | | | | |
| Japan | 63.6 | 211.9 | - | - | 353.1 | 271.9 | 900.5 | 452.0 | 2,253.1 |
| South Korea | - | - | - | - | 3.5 | 35.3 | 300.2 | 123.6 | 462.5 |
| Taiwan | - | - | - | - | - | - | 70.6 | 49.4 | 120.1 |
| **Total Exports** | **63.6** | **257.8** | **692.2** | **42.4** | **360.2** | **307.2** | **1,271.3** | **625.1** | **3,619.7** |

*Less than 2 billion cubic feet.

Note: Sum of components may not equal total because of independent rounding.

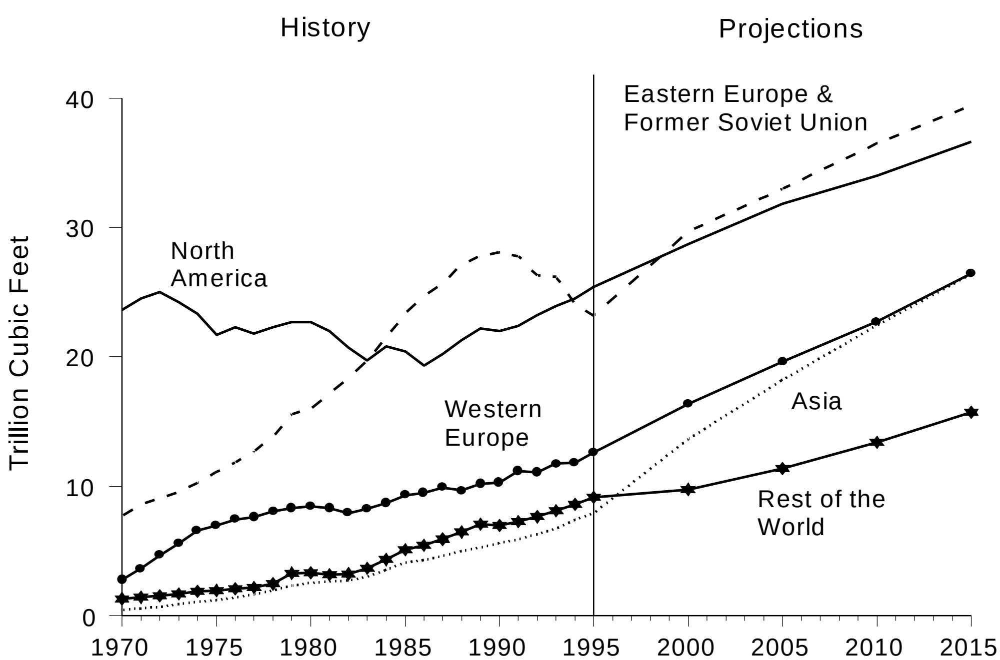
Source: Energy Information Administration, Office of Oil and Gas, derived from the British Petroleum Company, *BP Statistical Review of World Energy 1997*.

## Figure SF2. 1996 LNG Trade




Source: British Petroleum Company, *BP Statistical Review of World Energy 1997.*

## Figure SF3. Natural Gas Consumption by Region, 1970-2015




Source: Energy Information Administration, *International Energy Outlook 1997.*

supply sources and are candidates for additional LNG development. Their needs are discussed in a later section. Gas markets in Central and South America also are expected to undergo substantial development during the forecast period, with consumption increases of about 5.3 percent annually. Much of the additional consumption will be used to supply the region's growing needs for electric power and industrial energy. Heretofore the region has relied heavily on hydroelectric power, and natural gas use will permit substantial diversification in energy use for power generation.

Industrialized countries, where natural gas markets are most mature, will also increase their reliance on natural gas. Over the next two decades, demand in the industrialized countries is expected to grow by 2.6 percent annually, more than twice the rate of increase in oil use. In the United States, gas demand is expected to rise by 1.7 percent annually, mainly because of growth in gas-fired electricity generation.

Among the industrialized regions, Western Europe is projected to have the highest growth rate in gas use, at 3.8 percent. Privatization and restructuring of the electric utility sector in many countries of Western Europe have resulted in plans to increase the use of natural gas for generating electricity. Further, many nations of Western Europe view natural gas use as a way to decrease greenhouse gas emissions. European governments are encouraging the development of gas infrastructure in an attempt to move away from reliance on the more carbon-intensive coal and oil.

In Eastern Europe and the former Soviet Union (EE/FSU), gas consumption is expected to rise by 2.7 percent annually. Much of the projected growth in this region is attributed to the countries of Eastern Europe, where economic recovery occurs more rapidly over the forecast period than in the FSU. Eastern Europe's gas demand grows by 5.2 percent per year in the forecast, whereas continued slow economic growth in the FSU leads to a more modest annual rate of 2.3 percent. Total gas demand in the EE/FSU rises by 70 percent over the forecast period. An infrastructure that is fast becoming integrated with the gas system of Western Europe supports the growth in East European gas use.

### *Even Greater Demand for Natural Gas May Result If Caps on Carbon Emissions Are Put into Place*

A significant uncertainty that was not addressed in the *IEO97* projections is the potential for caps on carbon emissions. The same level of energy derived from burning natural gas saves 50 percent of carbon emissions relative to coal and 30 percent relative to oil. Thus, if the world's governments move to policies that cap carbon emissions, substantial fuel substitution is likely. From a resource standpoint, natural gas could support even higher growth rates than currently projected, as potential sources of natural gas supply are far larger than those currently identified as proved reserves. Proved reserves represent producible gas in known fields that have access to infrastructure to move gas to market. The level of proved reserves worldwide could be vastly expanded by developing the infrastructure capacity.

### *Potential Supplies Are Substantial But Growth of Natural Gas Is Hindered by Infrastructure Requirements*

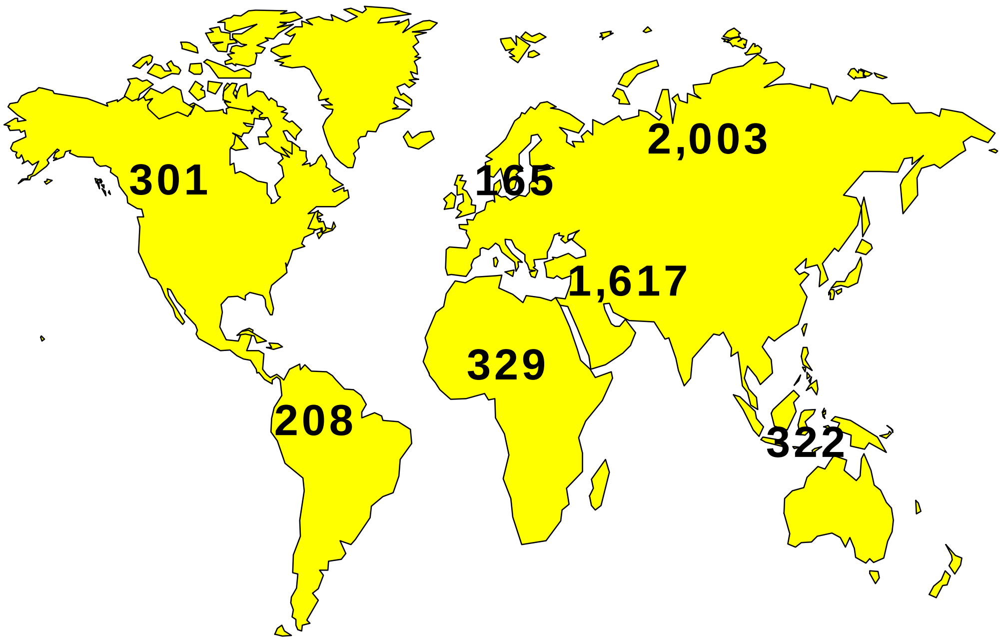
As of January 1, 1997, the world's proved world natural gas reserves[3] were estimated to be 4,945 trillion cubic feet (Figure SF4), 11.6 trillion cubic feet more than the estimate for 1996. Whereas natural gas reserves have declined slightly in the industrialized countries during the past decade, they have increased fairly dramatically in the EE/FSU and in the developing countries (Figure SF5). Between 1995 and 1996, gas reserves in the Middle East grew by 20 trillion cubic feet, whereas the combined reserves of Africa, Western Europe, and Asia declined by about 19 trillion cubic feet.

About 73 percent of the world's proved gas reserves are located in the FSU and the countries of the Middle East (Figure SF6). Reserves in the industrialized countries of the world have remained fairly stable over the past 20 years, although they have fallen continuously since 1993. On the other hand, reserves in the EE/FSU and developing countries have more than doubled.

Natural gas reserves are less geographically concentrated than oil reserves worldwide. Further, despite high rates of increase in gas consumption, especially over the past decade, regional reserves-to-production ratios tend to be high, indicating excess capacity and the potential for greater exploitation of this resource. For example, Central and South America have a reserves-to-production (R/P) ratio of 73.9 years, the EE/FSU 80.4 years, and the Middle East more than 100 years.[4] In contrast, the United States and Canada had R/P ratios for 1995 of 9.2 and 12.8, respectively.[5] Additionally, in many areas, deposits of gas are known to exist but are not counted as reserves because the infrastructure needed to gather and distribute the gas is not available.

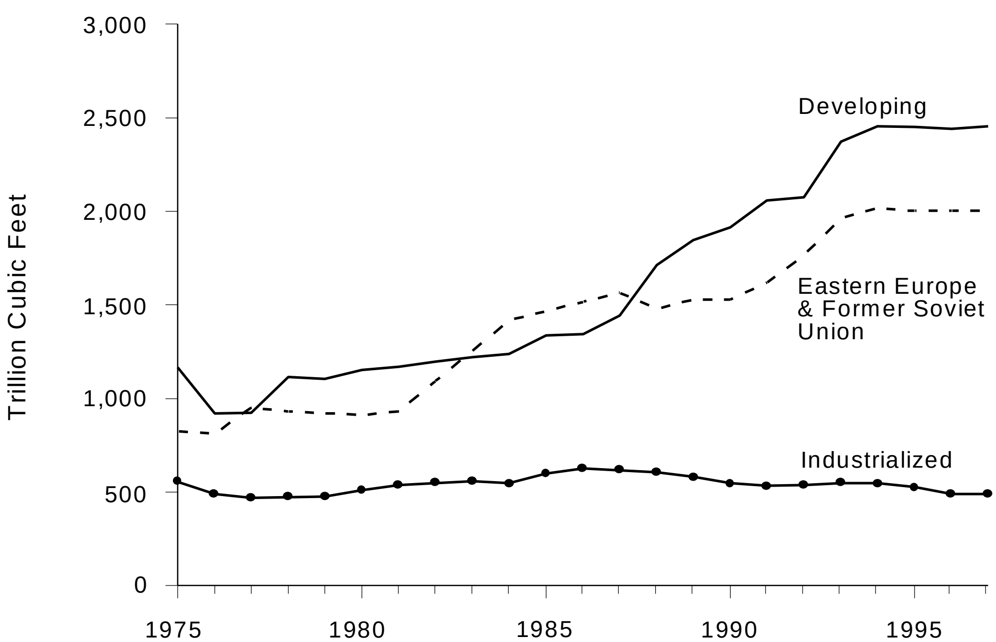
Lack of infrastructure is the major barrier to increased worldwide gas consumption. Most gas presently moves

**Figure SF4. Global Gas Reserves as of January 1, 1997**
(Trillion Cubic Feet)



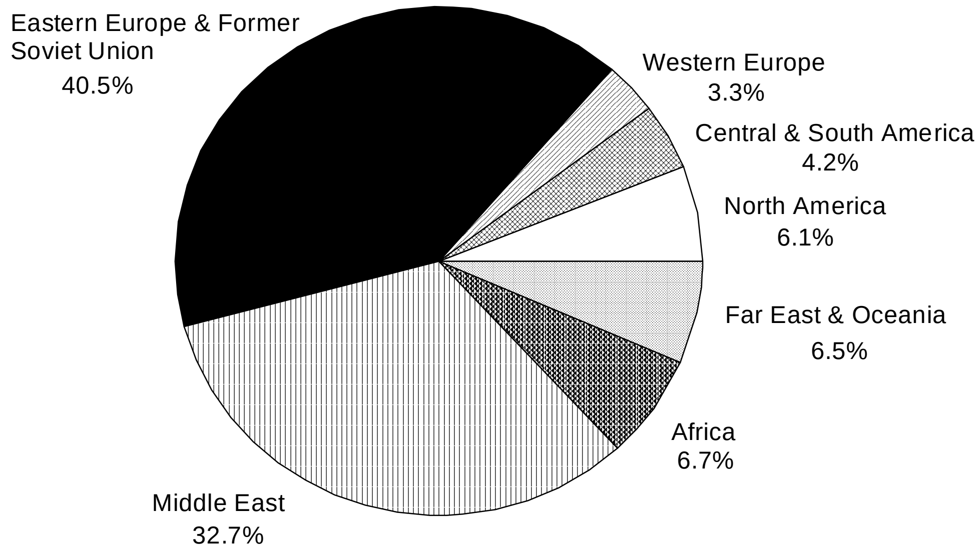

Source: *Oil and Gas Journal* (December 30, 1996).

**Figure SF5. World Natural Gas Reserves by Region, 1975-1997**




Sources: **1975-1996:** "Worldwide Oil and Gas at a Glance," *International Petroleum Encyclopedia*, various issues. **1997:** "Worldwide Look at Reserves and Production," *Oil and Gas Journal*, (December 30, 1996), pp. 40-41.

**Figure SF6. Regional Distribution of Global Gas Reserves**




Source: *Oil and Gas Journal* (December 30, 1996).

by pipeline, which requires proximity to demand areas and the ability to lay pipe over reasonable terrain. Throughout the world, major efforts are proceeding to expand gathering, transmission, and distribution capacity in order both to promote and support the projected growth in natural gas demand. In 1996, more than 12,000 miles of new natural gas pipeline were completed,[6] and an additional 15,000 miles were under construction. Regionally, more than 50 percent of ongoing pipeline construction activity is in South America and Asia—areas that currently account for less than 15 percent of the world's gas consumption. Proposals and plans for further infrastructure expansion are numerous. Enron in 1995 cataloged project proposals involving the construction of 300 or more miles of pipeline per project.[7] Nearly 400 such projects were identified, involving 77,000 miles of additional construction.

The largest of the proposals calls for a pipeline network that would link all of the gas producing and consuming nations of the Pacific Rim of Asia—the same region that accounts for the bulk of the world's LNG imports. The proposed pipeline network would stretch thousands of miles from Australia and New Zealand north to Southeast Asia, China, Taiwan, South Korea, Japan, and Russia. Because of the huge expense and major logistical problems that are involved, this proposal is not very likely to become a reality over the next 20 years. However, plans are being made to build one component of the proposed network—pipelines linking gas supplies from the Russian Far East to China and other nearby countries such as Japan. On June 27, 1997, China and Russia agreed to a $5 billion project to develop gas reserves for export to China; under this project, Russia eventually would ship almost 1 trillion cubic feet of natural gas annually to China. The dynamic to expand infrastructure to utilize abundant natural gas resources is strong and will result in many more miles of pipeline development beyond the 15,000 miles of construction currently underway. Still, there are many areas of the world where pipeline construction from supply to demand areas is currently not an option and LNG transport is presently the only way to accommodate the development of these supply areas and markets.

### *LNG Consumption Appears To Be Increasing Even More Rapidly Than Consumption of Piped Gas*

LNG consumption appears to be increasing even faster than that of piped gas, making it likely that the LNG share of total gas will rise over the next 10 to 15 years. LNG markets appear to be entering a new round of expansion, with a more diversified range of customers and suppliers. The largest proportion of increased LNG use will occur in Japan, South Korea, and several newly industrializing Asian countries, including India, Thailand, and perhaps China. There are a growing number of LNG supply contracts worldwide—despite the fact that average LNG prices tend to be higher than prices of competing fuels—primarily because it is environmentally a clean fuel (compared with coal and oil) and its markets tend to be where pipelines are unavailable.

LNG is a major share of the total natural gas consumed in several countries of the world, particularly in Asia. LNG accounts for more than 97 percent of Japan's total natural gas consumption.[8] The bulk of Japan's LNG currently comes from Indonesia, although supplies are also imported from Australia, Brunei, Malaysia, the United Arab Emirates, and the United States (68 billion cubic feet in 1996).[9] In 1996, Japan further diversified its supplies by signing a long-term agreement with Qatar. The January 10, 1997 delivery of 65,000 metric tons (about 3.2 billion cubic feet) of LNG marked the entrance of Qatar into the industry.[10] Many analysts see the agreement between Qatargas and Chubu Electric Power of Japan as a major industry milestone. Qatargas is contracted to supply Chubu with up to 6 million metric tons of LNG per year (292 billion cubic feet) for a 25-year period. This is the first of three projects under way to export up to 12 million metric tons of gas (584 billion cubic feet) per year from Qatar's North Field by 2000. The second project, Ras Laffan LNG, is under construction and is scheduled to be onstream by mid-1999.

South Korea is the second largest consumer of LNG (following Japan) worldwide.[11] Virtually all natural gas consumed in South Korea is LNG. South Korea began importing LNG about 10 years ago in order to provide a cleaner alternative fuel to the electric utility sector, which has continued to provide much of the growth in gas consumption since that time.[12] About 10 percent of electricity generation in South Korea is attributable to gas.[13] The Korea Gas Corporation (Kogas) is currently increasing gas supplies to residential, commercial, and industrial users through 32 local natural gas and liquefied petroleum gas distributors.[14] Fifteen of these distributors already supply gas to end-use sectors other than electric utilities. In the future, the electric utility sector is expected (by Kogas) to lose share to the rapidly growing (mostly) residential sector use. The residential sector share of natural gas use is expected to grow from 34 percent to 40 percent between 1996 and 2010. Kogas plans to expand its gas trunkline from 2,200 miles to 3,700 miles by 2006. The company has estimated that LNG imports will more than triple between 1996 and 2010.

Both Japan and South Korea have plans to increase reliance on nuclear power, as well as natural gas, to meet their energy needs. Japan’s nuclear power consumption is expected to grow by 32 percent between 1995 and 2015, and South Korea’s by 120 percent. Natural gas demand in Japan will increase by 83 percent over the next 20 years according to EIA’s *International Energy Outlook 1997*. The Korea Energy Economics Institute projects that LNG consumption in South Korea will grow by 173 percent over the next 15 years alone.

Plans for nuclear expansion in these two countries may be constrained as a result of growing public opposition to the industry. In Japan, a municipal referendum seeking public approval for construction of a nuclear power station in Maki, Niigata, was rejected by local residents in August 1996. Moreover, the March 11, 1997 fire and explosion at a low-level radioactive waste-processing plant at Tokai Mura near Tokyo may increase public concern about Japan’s nuclear plans. Public opposition to nuclear power has also been seen in South Korea, where demonstrations have been held to protest an agreement between Taiwan and North Korea to ship Taiwan’s low-level radioactive waste to North Korea for storage.

There is expanding interest in LNG in several other countries of developing Asia. Thailand and India, in particular, have major plans for establishing LNG supplies. Thailand signed contracts with Oman to begin shipments of LNG in 2003.[15] At the end of 1996, India's state-owned Gas Authority of India, Ltd., made an international call for LNG supplies as part of a $10 billion project to diversify its energy sources.[16] The government has identified LNG as a long-term fuel for the electric power sector and plans to set up two regasification plants: one at Ennore, near Madras, on India's southern coast and one at Mangalore on the western coast. India's Gas Authority has begun talks with Qatar's Ras Laffan LNG Company in an attempt to secure 5 million metric tons (244 billion cubic feet) of LNG for the planned projects.

Four more LNG import terminals could be developed in India besides the two planned at Ennore and Mangalore in the southern part of the country. Paradip and Visakhapatnam on the east coast and Kandla and New Mumbai on the west coast are locations for additional terminals for import of 2.5 million metric tons per year (122 billion cubic feet) each. Each could cost about $1.1 billion, and all the new terminals could be online by 2005. India would like to import LNG both from Persian Gulf and southeast Asian countries.

Even China may emerge as a market for LNG. Shanghai is seeking foreign funds and technology to help build a $300 million LNG storage unit.[17] The city wants to reduce its reliance on coal in favor of cleaner energy sources.

According to the Shanghai Planning Commission, coal currently meets 72 percent of Shanghai's fuel needs, and consumption is projected to reach 60 million metric tons per year by 2000 and 90 million metric tons per year by 2010. To diversify fuel use, Shanghai would import 3 million metric tons (146 billion cubic feet) of LNG per year. A prospective LNG project would take an estimated 5 years to complete and would import gas from Southeast Asia and Australasia.

European buyers of LNG include the Western European countries of Turkey, France, Belgium, and Spain.[18] LNG accounted for 81 percent of Spain's total natural gas consumption in 1995. However, pipeline connections to Algeria and to the European grid will cause LNG to lose share in Spain to conventional gas sources in coming years. Demand for LNG in Western Europe may grow by as much as 155 million metric tons (7.5 trillion cubic feet) per year by 2010, around 90 million metric tons (4.4 trillion cubic feet) of which are covered by existing supply contracts.[19] Some 50 million metric tons (2.4 trillion cubic feet) of European LNG demand could be met by supplies from the Middle East. The Atlantic LNG project currently under construction in Trinidad, scheduled for completion in 1999, is expected to market a large part of its output to Spain and the Northeast United States.

In the United States, LNG accounts for a small portion of total gas consumption. This is not expected to change materially over the next decade, although some increase in purchases is expected, especially once the Trinidad project comes online in 1999. In addition, most major heavy-duty engine manufacturers have plans to build and test LNG engines for use in large trucks.

### *LNG Is a Costly Option Requiring Large Capital Investments*

Although worldwide gas inputs for LNG facilities are relatively cheap—based on large and easily produced reserves—processing and transportation equipment is capital intensive and highly specialized, requiring billions of dollars of investment for each new facility. For each million cubic feet of gas delivered to end users, less than 30 percent of the cost is associated with resource supply. The balance reflects the costs of processing and transportation.[20]

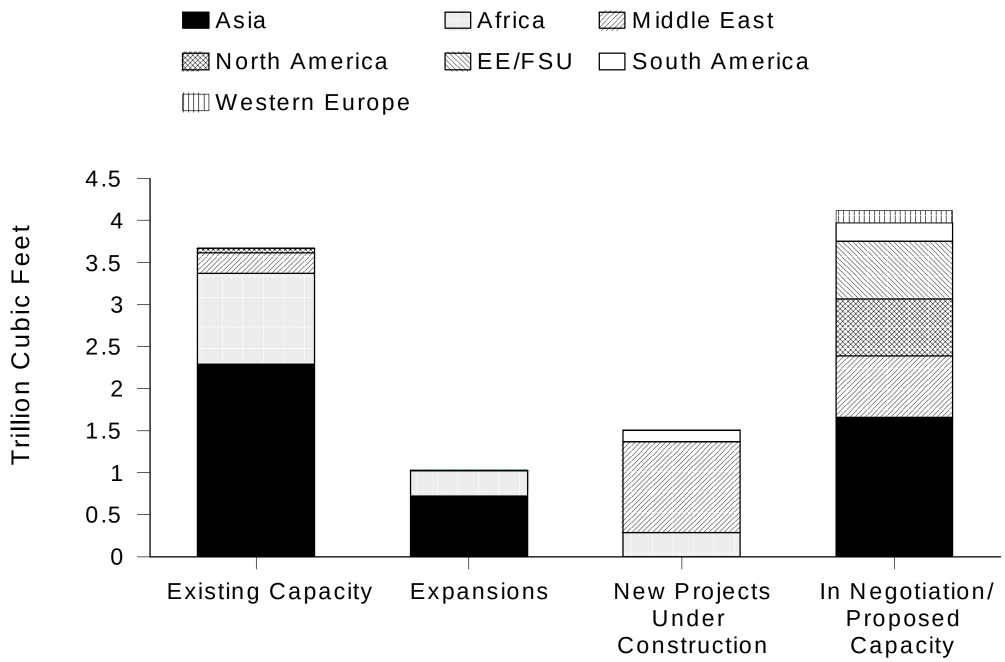
Existing liquefaction plants currently account for more than 3.6 trillion cubic feet of capacity per year (Figure SF7). Planned extensions to existing capacity involve additions of more than 1.0 trillion cubic feet of capacity. New projects under construction should add another 1.5 trillion cubic feet of capacity. Additional prospective capacity additions ranging between 1.4 and 4.1 trillion cubic feet are in various stages of planning and negotiation.[21] Thus, it is possible that worldwide LNG processing capacity could nearly triple in the next decade or so. Much of the proposed capacity will be in Asia where liquefaction capacity has the potential for more than doubling, to total more than 4.6 trillion cubic feet (Tcf) per year (Figure SF8). The Middle East, where capacity currently stands at 0.2 Tcf per year, has projects under construction that will bring total capacity to nearly 1.3 Tcf per year, with an additional 0.7 Tcf being considered for post-2000.

LNG projects comprise several distinct elements, each of which is necessary to implement a successful project:

- **A large, low-cost source of natural gas.** A successful LNG project must have sufficient proved reserves of natural gas to support liquefaction capacity for 15 to 20 years. To ensure adequate "deliverability" of gas even at the end of the project, reserves ought to be 25 to 35 times larger than the annual capacity of the plant. For example, a 500-million-cubic-foot-per-day project would require proved reserves of 5.48 to 7.67 trillion cubic feet.[22] In addition, production costs (including applicable production taxes levied by the host government) need to be low—typically, less than $1.00 per million Btu, and preferably on the order of $0.50 per million Btu. On the other hand, if natural gas production yields significant volumes of condensate or natural gas liquids, the revenues from petroleum coproduction may be sufficient to cover the cost of natural gas production, permitting the LNG project to be economically viable despite low natural gas feedstock prices. Extracting liquids and condensates, while usually profitable, exacts a volumetric cost. Typically, 10 percent or so of gross gas production disappears in the form of extracted liquids and nonhydrocarbon gases. Thus, gross production must exceed the volume of gas delivered to the liquefaction plant by the amount of shrinkage.

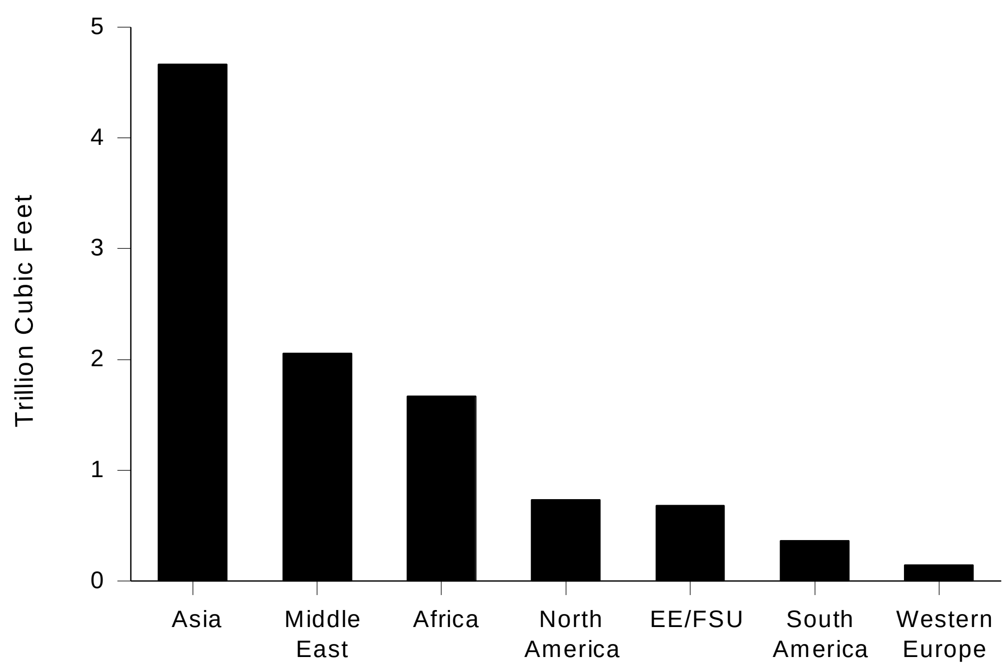
- **A liquefaction facility, including a jetty and loading facilities for LNG tankers.** The liquefaction plant is typically the most expensive element of an LNG project. The cost will depend on a host of site-specific factors and on project scale, with larger projects having lower unit costs. As a rule of thumb, $300 to $900 million of capital cost for each 1 million metric tons per year (about 133 million cubic feet per day) of capacity seems to be typical of current projects.[23] How this capital cost is distributed over the life of an LNG project will depend on a host of financing

## Figure SF7. Status of Worldwide LNG Capacity: Existing, Planned, and Potential as of 1996




Note: EE/FSU = Eastern Europe & Former Soviet Union.
Source: Petroleum Economist Ltd., *Petroleum Economist*.

## Figure SF8. Potential for World Liquefaction Capacity by Region as of 1996




Note: EE/FSU = Eastern Europe & Former Soviet Union.
Source: Petroleum Economist Ltd., *Petroleum Economist*.

details and inflation assumptions, though principally on the developer's target rate of return on capital. Operating costs are relatively minor. Liquefaction is a very energy-intensive process. Typically, about 8 to 9 percent of the natural gas delivered to an LNG plant is used as plant fuel, but as noted above, the cost of the natural gas delivered to the liquefaction plant is inherently very low.[24]

- **LNG Tankers.** Each project requires several dedicated LNG tankers, which are among the most complex and expensive merchant ships ever built, because of their double hulls and special lining. Each new 135,000 cubic meter (3 billion cubic foot) capacity tanker costs on the order of $260 million. The number of tankers required for a project depends primarily on the distance between the liquefaction plant and the customer. In general, transportation costs increase linearly with distance. Other less important issues include the cost of bunker fuels for the tanker and the cost of arrangements for spare transport capacity when dedicated tankers are being refitted. Finally, the tanker's LNG cargo is kept cool by evaporating a fraction of the cargo ("boiloff") and burning it as boiler fuel. Typically, about 0.15 to 0.25 percent of the cargo is consumed per day, during which the tanker will travel about 480 nautical miles.[25] Thus, moving LNG from the Persian Gulf to Japan (about 7,000 nautical miles) consumes about 3.6 percent of the cargo (see Box, "LNG Transport Distances and Associated Gas Losses").

- **Regasification Plant.** LNG can be unloaded only in specialized terminals, which typically include a jetty and unloading facilities, LNG storage equal to at least a single tanker cargo, regasification facilities, and connections to pipelines. The cost of the regasification terminal varies with capacity, local construction costs, and the amount and type of site preparation costs, but it would be in the range of several hundred million dollars. Regasification plant costs are typically considerably lower than liquefaction plant costs. At present, there are regasification plants in most major consuming markets. Opening up LNG markets in new countries (for example, China or the Philippines) would require a considerable initial infrastructure investment. A U.S. Department of Energy study estimated the capital cost of a new regasification plant at $700 million (1988 dollars) for a 500-million-cubic-foot-per-day facility, equivalent to $0.56 per thousand cubic feet. Regasification energy requirements will also consume a further 2.5 percent of the delivered LNG. The marginal cost of using an existing regasification plant with excess capacity, or expanding the capacity of an existing plant, would be far lower than the cost of building a new "greenfield" facility.

The large capital costs of each link in an LNG project impose their own logic. Projects can be undertaken only by large organizations with sufficient financial capacity and strong project management skills. A typical customer would be a mid-sized natural gas distribution company with 50,000 to 100,000 customers. A successful project requires the cooperation of the host government (where the gas resources are located), the entity that owns the natural gas rights (private or state), the government of the consuming country, consuming organizations (national or private electric utilities, gas companies, etc.), and a host of specialized organizations, including shipyards, financiers, tanker operators, construction companies, and process technology licensors. Agreement must be reached *in advance* regarding the distribution of the costs, the benefits, and the considerable risks associated with the project. Reaching these agreements generally requires protracted negotiations, as well as considerable upfront expense for risk-reducing feasibility and engineering design studies.

No LNG project is likely to proceed unless the developers receive some assurance that they will be able to earn an acceptable return on their multibillion-dollar investments. A successful LNG project requires a price that is low enough to motivate consumers to use large volumes of natural gas, backing out fuel alternatives, yet still high enough to persuade developers and borrowers to actually build the project. LNG developers will seek (but not always find) a long-term contract for their product at a price that is sufficient to cover their capital costs, which includes "take or pay" and "floor price" arrangements to ensure that the project can service its debts even in a lower-than-anticipated energy price environment.[26] It is also common for consumers to be offered or to take an equity stake in LNG projects, so as to encourage a common interest among the buyers and the sellers.

From the above review, it is clear that LNG project costs can vary considerably, particularly with respect to the effects of local construction costs. As a summary estimate, however, a successful LNG project might have production costs of $0.50 per million Btu, liquefaction costs of $2.50 per million Btu, and transport costs of $0.75 per million Btu, for a typical project cost of perhaps $3.75 per million Btu delivered to the regasification plant. The actual delivered cost of LNG to Japan under a mix of spot and long-term contract arrangements to Japan is typically $3.00 to $4.00 per million Btu.[27]

## LNG Transport Distances and Associated Gas Losses

Moving LNG long distances incurs an inevitable loss of a portion of the cargo. Evaporation from the cargo, or boiloff, supplies most of the ship's fuel needs. Losses in transit clearly reduce the value of the shipment. Volumes lost depend on a number of factors such as distance, ship speed, and the boil-off rate. These factors may vary for many reasons including the age of the vessel and the weather conditions during the voyage, but the distance seems to be the primary determinant.

Distances and estimated losses for routes between various supply locations and the two operating U.S. LNG import facilities are shown in the following table. In addition, values associated with shipments to Japan from selected source locations are provided in the third section of the table. The proximity of Alaska to Japan gives it a comparative advantage in shipping gas losses relative to supplies from Middle East sources.

| From | To | Distance (approx. miles) | Gas Losses (as fraction of shipment) |
|---|---|---|---|
| Algeria | Everett, MA | 3,303 | 1.7% |
| UAE | Everett, MA | 7,871 | 4.1% |
| Australia | Everett, MA | 11,874 | 6.2% |
| Venezuela/Trinidad | Everett, MA | 2,075 | 1.1% |
| Algeria | Lake Charles, LA | 4,962 | 2.6% |
| UAE | Lake Charles, LA | 9,533 | 5.0% |
| Venezuela/Trinidad | Lake Charles, LA | 2,275 | 1.2% |
| Persian Gulf | Japan | 7,000 (1) | 3.6% |
| Indonesia | Japan | 2,400 (2) | 1.3% |
| Alaska | Japan | 3,200 (3) | 1.7% |

Note: Gas losses were derived based on an assumed tanker speed of 20 nautical miles per hour and gas losses of 0.25 percent per day.

Source: Energy Information Administration (EIA), Office of Oil and Gas. All distances are from *Potential for Long-Term LNG Supply*, Arthur D. Little (August 1991) prepared for Gas Research Institute, except for: (1) EIA Office of Integrated Analysis and Forecasting as published in *Issues in Midterm Analysis and Forecasting 1997* (July 1997); (2) EIA Office of Oil and Gas, derived from *Distances Between Ports: 1965*, U.S. Naval Oceanographic Office (1965);and (3) Yukon-Pacific Corporation submission on the Trans-Alaska Gas System (TAGS) to the National Petroleum Council (1991).

### *Recent Market Developments Have Improved the Prospects for Future Growth*

Several interesting market developments in the LNG business have created a modest boom in LNG operations, improving the prospects for future growth. LNG projects, as previously noted, have generally been based on a firm supply contract between buyer and seller, in which the buyer is required to "take or pay," while the seller is required to "deliver or pay." LNG projects are thus designed to deliver the contractual amount of gas with a high degree of reliability. In practice, this has meant designing-in excess capacity, so that excess liquefaction capacity is available most of the time and "spare" tankers are available to cover scheduled overhauls. The cost of this excess capacity is embedded in the project's main contracts. Consequently, many LNG producers have volumes of LNG available in excess of contract volumes, for which the marginal cost of production and transportation is a fraction of the full cost of the main contract volumes. Producers have proven willing to sell these volumes at competitive prices on a developing "spot" market

Spot trading in LNG currently accounts for about 3 percent of the total market, compared with nearly zero volumes as recently as 1992.[28] In the United States, the Boston-based Cabot Corporation has signed an agreement with Australia's Northwest Shelf LNG project to purchase three cargoes of LNG on a spot sales basis. The first shipment of 2.5 billion cubic feet was delivered in May 1997 with two additional shipments scheduled for later this year. In an attempt to enter the European LNG market, Qatar's Qatargas LNG project plans to sell spot cargos to Europe beginning in September 1997.[29]

Development of the LNG spot market has also been stimulated by other events. Contract disputes between buyers and sellers occasionally have made LNG from existing plants unexpectedly available. Further, some LNG projects are now old enough so that their original 20-year supply contracts have expired. The owners of these projects have considerably more pricing flexibility than owners of prospective future projects. Projects that have collapsed have produced a flock of uncommitted LNG tankers available for spot charter or sale at a fraction of construction cost. As of 1993, one source estimated that nine large LNG tankers (14 percent of the worldwide fleet) were idle.[30] Finally, the cost of adding incremental capacity to existing plants is often considerably lower than building a new plant. This has paved the way for the expansion of the market through lower cost "capacity creep." The Institute for Energy Economics of Japan estimates that typical capacity for existing LNG liquefaction plants may be as much as 25 percent in excess of rated "nameplate" capacity.[31] In the United States, the Everett, Massachusetts, LNG regasification plant operates at 30 billion cubic feet of its full capacity of 92 billion cubic feet. By 1999, this facility is expected to reach full capacity, potentially expanding to 140 billion cubic feet by 2005. Expansion at the Lake Charles, Louisiana, regasification facility is also possible; the Cove Point, Maryland, and mothballed Elba Island, Georgia, facilities could be reopened for LNG importation under the right economic circumstances.

The development of the LNG spot market has also led to an apparent relaxation of constraints on new project development. Rather than nailing down project volumes through a set of long-term contracts, operators in the 1990s have proven willing to go ahead with projects in the absence of long-term contracts for the full volume, in the faith that sufficient additional contracts will ultimately materialize, or, at worst, that a portion of the product can be sold (perhaps at a discounted price) on the spot market. Thus, the development of an LNG spot market has apparently reduced the volume risk inherent in new LNG projects.

LNG holds considerable potential for future natural gas trade, which can be unlocked in several different ways:

- Countries such as Thailand, Brazil, the Philippines, China, and India may elect to build regasification facilities in the future.
- LNG capital costs may continue to decline with improving technology. The minimum efficient scale for LNG projects may decline, creating opportunities for smaller export projects.
- The development of an active spot market with more exporters and importers may improve utilization rates on expensive fixed liquefaction and transport capacity, as well as reduce project risk.
- Markets for premium-priced "clean" fuels may expand in current and potential consuming countries with increasing wealth and increasing public concern about air quality or greenhouse gas emissions.
- LNG use to cover peak consumption periods and to enhance gas system reliability may grow.

LNG projects, however, are not created in a vacuum. They must compete with other fuels and even with other gas export technologies. Today LNG projects compete against coal and petroleum products in power generation markets and, potentially, against "town gas," middle distillates, and liquefied petroleum gas in smaller premium residential markets.

## *Alternative Technologies for Moving Natural Gas from Supply Sources Are Actively Being Investigated*

LNG is only one way to move natural gas from remote sources to market areas. Gas marketing alternatives to LNG that may or may not be superior must be considered in any assessment of the long-term potential for LNG and natural gas, although the future impact of these alternatives cannot be determined with precision at present. There are a number of options for marketing natural gas, which depend either on converting the gas into another product or the use of alternative approaches to natural gas transportation.

### Gas-to-Liquids Technology for Conversion to Petroleum Products

Gas-to-liquids technology (GTL) refers to the conversion of natural gas into synthetic hydrocarbon liquids, particularly middle distillates.[32] With the transportation market, particularly in Europe, emphasizing the use of diesel fuel, rather than gasoline, this process is an interesting alternative for developing natural gas

## Carbon Emissions from GTL-Produced Synthetic Diesel

A key issue in the supply and consumption of any fuel is the resulting relative environmental impact. Carbon emissions associated with the supply and combustion of 1 quadrillion Btu of natural gas- or petroleum-based fuels can vary widely from 18.4 million metric tons for compressed natural gas (CNG) to 26.8 million metric tons for synthetic-derived diesel fuel based on gas-to-liquids (GTL) technology (see following table). These estimates are based on supplying 1 quadrillion Btu of energy to the consumer (excluding delivery) and its use; thus they account for carbon content of the original fuel and conversion losses.

Generally, the carbon caused by the supply and use of either petroleum- or synthetic-derived diesel is comparable, and that from natural gas is comparable whether it is used as CNG or LNG. Carbon emissions from the consumption of 1 quadrillion Btu of natural gas are less than those from diesel, however, the consumption efficiency of each fuel must be recognized. For example, better transportation efficiency of diesel generally offsets this benefit, resulting in no clear advantage in carbon emissions per mile traveled for either of the four fuels when consumed in transportation.

**Carbon Produced from Supply and Use of 1 Quadrillion Btu, by Fuel**

| Fuel | Million Metric Tons of Carbon |
|---|---|
| Petroleum-based diesel | 25.5 |
| Synthetic diesel derived from natural gas | 26.8 |
| Compressed natural gas | 18.4 |
| Liquefied natural gas | 19.4 |

Source: Energy Information Administration, Office of Oil and Gas, derived from assumptions and methodology provided by the Department of Energy's Office of Fossil Energy.

supplies. Petroleum products are far easier to transport and market than LNG. They can be moved in existing pipelines or products tankers and blended with existing crude oil or product streams. No special contractual arrangements are required to sell them, and there are numerous suitable domestic and foreign markets. The key to the economics are the capital and operating costs of the plant, feedstock costs, and, secondarily, the ability of the operator to achieve high utilization rates. Owners of natural gas reserves will naturally be interested in whether LNG or gas-to-liquids plants yield the largest return on investment. Current economics and technology favor increased conventional crude oil production, but GTL technology provides an economically viable option for exploiting remote gas deposits without exceeding crude oil production quotas (see Box, "Carbon Emissions from GTL-Produced Synthetic Diesel").

Currently Royal Dutch/Shell operates a project at Bintulu (Malaysia) with a capacity to produce 12,500 barrels per day of middle distillates from 100 million cubic feet per day of natural gas. Other projects under development include two in Qatar. One project is being negotiated between Exxon and Qatar aimed at producing 50,000-100,000 barrels per day of middle distillates, naphtha, and catalytic cracker feedstock from 500 to 1,000 million cubic feet per day of gas. This project is expected to cost from $1.2 billion to $2.4 billion and will rely on Exxon's Advanced Gas Conversion Technology 21st Century (AGC-21) process. A second Qatar project undergoing a feasibility study calls for a 20,0000-barrel-per-day plant to be developed by Sasol (South Africa) and Phillips Petroleum (USA) with Qatar General Petroleum. It will use Sasol's Slurry Phased Distillate GTL process technology to produce naphtha and distillate. A U.S.-based effort to develop more advanced GTL technology is the DOE joint venture with Air Product and Chemicals, an 8-year project funded with $84 million to develop GTL technology with lower associated costs. Statoil (Norway) and Sasol (South

Africa) have a joint venture to develop GTL for large-scale offshore production. While thermal efficiencies of current GTL applications are in the range of 60 to 65 percent, new technology is expected to improve them.

Domestically, the Alaskan North Slope is a potential area for application of GTL technology. This would involve transporting the produced liquids via the Trans-Alaska Pipeline System (TAPS) to tankers at the port of Valdez in south Alaska, which has favorable implications for the economics of TAPS operations over the longer term.

### Converting Natural Gas into Other Products

Natural gas can be converted into other marketable products. Present techniques allow the production from natural gas of ammonia / urea, methanol, and methyl tertiary butyl ether (MTBE). Ammonia, a common industrial chemical, has its most important use in the production of urea, which is the principal building block of nitrogen fertilizers. Most new export-oriented plants integrate ammonia and urea manufacture. Expanded use of natural gas for this purpose is expected to be limited by fertilizer market growth and political differences between countries. Methanol is an industrial chemical feedstock and can be used as an alternative liquid transportation fuel. Recently, Norway's Statoil and Conoco Inc. dedicated a $1 billion natural gas-to-methanol plant at Tjeldbergodden, Norway, with capacity to meet 15 percent of Europe's annual methanol consumption.[33] Absent higher oil prices or legal requirements for alternative transportation fuels, the methanol market likely will remain a relatively small chemical-oriented market, rather than a large fuel-oriented market. MTBE can be blended with gasoline to produce reformulated gasoline. It also is used sometimes in lesser proportions as an "octane enhancer" in unleaded "conventional" gasoline. However, even a very large expansion of MTBE markets would not entail very large increases in natural gas usage.

## *International and Deepwater Pipeline Construction Is Advancing*

Another intriguing alternative to LNG is the building of natural gas pipelines in deep water or through difficult terrain that has previously been considered too difficult or too costly.

### International Pipelines

Gas pipelines are probably the least expensive and most effective means of moving bulk energy over long distances. International pipeline projects hold the promise of moving natural gas from places where it is plentiful (e.g., the Persian Gulf) to places where it is scarce (e.g., the Indian subcontinent). However, there are preconditions to successful implementation of an international pipeline project, which can be difficult to achieve:

- First, the governments along the route must be seen to be sufficiently stable (and have sufficient guarantees for private contracts) to make commitments that will be binding upon successor governments.
- Universal agreement must be reached among pipeline operators, consumers, intermediary states (if any), and resource owners on the distribution of costs and benefits from the project. Unreasonable behavior on the part of any party will prevent the project from going forward.
- There must be a large downstream gas market. As in the case of LNG projects, long-distance pipeline projects require large volumes to be economical. The U.S.-Canadian border is criss-crossed with pipelines. Europe has also developed an effective international gas transmission system. In South America, political and economic reform has had the side-effect of also making international pipeline projects possible. On the other hand, a large-diameter pipeline running from Iran to Pakistan and on to India, while feasible technically and economically, at present is highly unlikely for political reasons. There are many other potential projects affected by similar circumstances.

### Deepwater Pipelines

Pipelines have been successfully laid under the ocean and through mountains, swamps, tundra, and permafrost. The construction of large-diameter pipelines across the Mediterranean, connecting Algeria with Spain and Italy, has had a significant dampening effect on trans-Mediterranean LNG markets. The development of similar projects in Asia may have a similar effect. In recent years, the Oman Oil Company (mostly owned by the government of the Sultanate of Oman) has proposed a pioneering deepwater pipeline to connect Oman and India. This project is clearly an alternative to a Middle East-India LNG project, and it bypasses the technically easy but politically difficult problem of building an onshore or shallow-water pipeline via Iran and Pakistan. However, it has never been made clear who would be able to build the deepwater pipeline, nor how much it would cost. In the future, if the technical and economic hurdles can be overcome, there are many situations where deepwater pipelines could be effective competitors to future LNG projects.

### *Gas Hydrate Deposits Are a Potential Natural Gas Supply Source Close to Large Gas Markets*

Immense amounts of methane, the principal constituent of natural gas, naturally occur in gas hydrate deposits located in oceanic sediments and in sediments underlying the Arctic permafrost zone. These deposits constitute by far the largest potentially available source of methane on Earth. Worldwide, the amount of carbon bound in gas hydrates is conservatively estimated to be twice the amount that is believed to exist in all other fossil fuels on Earth. Global methane hydrate resource estimates made by various parties between 1977 and 1994 place the total methane volume resident in continental deposits in the range of 500 to 1,200,000 trillion cubic feet, and the volume resident in marine deposits in the range of 110,000 to 270,000,000 trillion cubic feet.

Massive concentrations of methane hydrate have been mapped in the relatively shallow continental shelf waters off the U.S. East Coast. Initial core drilling for scientific purposes was conducted last fall in a pair of hydrate-rich areas located off the coast of the Carolinas, each about the size of Rhode Island. These two areas are estimated by the United States Geological Survey to hold more than 1,300 trillion cubic feet of gas, which is about 60 times more than the total 1995 U.S. gas consumption of 21.6 trillion cubic feet. Hydrates also have been discovered off the coasts of California, Washington, and Alaska.

Other nations with indigenous or near offshore methane hydrate deposits have significant hydrate research efforts. Japan has a $50 million program in place, and plans to demonstrate methane hydrate production from the Nankai Trough off the East Coast of Honshu by 1999. Norway also has a methane hydrate research program, since there are large deposits in the North Sea. A potentially important offshoot application that Norway has already bench tested is marine shipment of natural gas in hydrate form, which is safer than shipping LNG and appears to be approximately as economic when scaled up.

The only place where commercial production of methane hydrate is currently taking place, although not by design, is in the Messoyakha Gas Field located in Western Siberia, Russia. The serial pressure decline and production data for this field provide a strong indication that an increasing portion of the gas production originates in a methane hydrate layer located 700 meters beneath the surface and 100 meters thick. In 1990 the gas from this layer comprised nearly half of total field production.

Considerable research is needed to characterize more accurately the geology of methane hydrate deposits, leading to the development of means to extract them safely and efficiently and the eventual conversion of this resource into an abundant, commercially viable source of relatively clean energy.

### *Summary: LNG Trade Through 2015 Is Expected To Show Large Increases But Later Technology Developments and Gas Hydrates Could Curb Further Expansion*

The outlook for both supply and demand for LNG looks strong for the period through 2015. Growing demand in the Asian markets, with an emphasis on the environmental advantages of natural gas as a relatively clean burning fuel, will be an important factor in that growth. Expansions of existing facilities and the construction of new facilities to accommodate the expected increases are either underway or in the planning stages. Global proved reserves of natural gas are plentiful, equaling approximately 60 years at current global production levels, and global natural gas resources are larger still.

The processing and transport of LNG, however, is a costly process. The development of competing technologies, such as gas-to-liquids, can alter the economics and the outlook for LNG beyond 2015. Two significant unknowns that can have an immense effect on the longer-term outlook include any agreements relating to caps on carbon emissions—which could substantially increase the need for natural gas—and secondly, gas hydrates, a huge potential resource that is not yet well understood. The close location of gas hydrates to some of the major markets for LNG could dampen growth in the LNG market, as would the rapid growth of nuclear power, which would provide another clean-air alternative for generating power.

# Endnotes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2. British Petroleum Company, *BP Statistical Review of World Energy 1997* (London, UK, June 1997), web site 165.121.20.76/bpstats.

3. Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, significant reserves in the probable category are included in "reserves" estimates for various countries, including those of the former Soviet Union.

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5. U.S. number is from the Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report 1995* (DOE/EIA-0216(95) (Washington, DC, November 1996; the Canadian number is from the Canadian Association of Petroleum Producers.

6. A.D. Koen and W.R. True, "World's Developing Regions Provide Spark for Pipeline Construction," *Oil and Gas Journal*, Vol. 94, No. 6 (February 5, 1996), pp. 29-31.

7. Enron Corporation, *The 1995 Enron Outlook* (Houston, TX, 1995), p. 22.

8. British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), pp. 26, 28, web site 165.121.20.76/bpstats.

9. All U.S. LNG exports (from Cook Inlet, Alaska) went to Japan in 1995.

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12. "Korea Weighs Import Alternatives to Feed Demand," *World Gas Intelligence*, Vol. 8, No. 6 (March 28, 1997), p. 9.

13. WEFA Group," *Far East Report 1995*, p. 9.3.

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17. "China/LNG: Shanghai Seeks LNG Funds," *Financial Times International Gas Report*, No. 320 (April 4, 1997), p. 29.

18. British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), p. 28, web site 165.121.20.76/bpstats.

19. V. Thomas, "LNG Shifts Course for New Markets," *Financial Times International Gas Report*, No. 321 (April 18, 1997), p. 33.

20. M.A. Adelman and M. Lynch, “Natural Gas Supply in the Asia-Pacific Basin,” in Massachusetts Institute of Technology Center for Energy Policy Research, *East Asia/Pacific Natural Gas Trade: Final Report*, 86-006 (Cambridge, MA, March 1986).

21. *Petroleum Economist* in conjunction with Citibank, “Liquefaction Plants in the World: Extensions and New Projects,” in *LNG—Evolution and Development* (London, UK, 1996).

22. The project needs sufficient gas to supply it for 15 to 20 years, with a terminal reserves-to-production ratio of 10 to 15, to ensure that the full contract amount can be produced at the end of the contract period. Arithmetically, if annual deliverability is 500 million cubic feet per day (0.1825 trillion cubic feet per year), then the amount needed is 25 to 35 x 0.1825 = 4.56 to 6.39 trillion cubic feet. If one accounts for “shrinkage” from extraction of natural gas liquids and nonhydrocarbon gases, as well as liquefaction plant and tanker fuel use, “wet gas” reserves need to be perhaps 20 percent larger than “dry gas” reserves, or 4.56 to 6.39 x 1.2 = 5.48 to 7.67 trillion cubic feet.

23. See table in T. Toichi, “LNG Development at a Turning Point and Policy Issues for Japan,” *Energy in Japan*, No. 126 (March 1994). A U.S. Department of Energy study estimated capital costs for a liquefaction plant, gas pretreatment, storage, and marine facilities at $1.7 to $2.1 billion 1987 dollars (depending on the availability of existing infrastructure) for a nominal 6.4-million-metric-ton-per-year plant, or $264 to $325 million per million metric tons of capacity. See: U.S. Department of Energy, Office of Policy, Planning, and Analysis, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector: Technical Report Three: Methanol Production and Transportation Costs* (Washington, DC, November 1989), p. 33.

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26. For instance, a recent account in the trade press of negotiations between Korean buyers and Omani sellers indicated that the Omanis were seeking a floor price of $2.25 per million Btu, with the LNG normally sold at 90 percent of the average cost of LNG imported into Japan. Japanese LNG import prices are, in turn, linked to crude oil import prices. “Oman LNG Finally Locks Up a Stubborn South Korea,” *World Gas Intelligence* (March 15, 1996), p. 1.

27. “Asian LNG Prices,” *World Gas Intelligence* (January 15, 1997), p. 10.

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30. C. Lyons, “Gas Deal Up for Re-negotiation,” *Seatrade World Review Monthly* (July 1994), p. 25.

31. T. Toichi, “LNG Development at a Turning Point and Policy Issues for Japan,” *Energy in Japan*, No. 126 (March 1994).

32. In this report, GTL refers to the conversion of the gas itself into another product. LNG describes the conversion of natural gas into shippable liquids by altering its state.

33. “Statoil, Conoco Dedicate Giant Norwegian Methanol Plant,” *Oil and Gas Journal*, Vol. 95, No. 28 (July 14, 1997), p. 26.