U.S. LNG Markets and Uses

Introduction

Liquefied natural gas (LNG) is expected to play an increasingly important role in the natural gas industry and energy markets in the next several years. LNG technology is used for natural gas supply operations such as imports via tanker ships and domestic storage, and in consumption such as for vehicle fuel. Interest in LNG imports has been rekindled by higher U.S. natural gas prices in recent years and technological advances that have lowered costs for liquefaction and regasifying, shipping, and storing LNG. Companies have announced plans for the construction of over a dozen LNG import facilities to serve U.S. markets since the beginning of 2001, although it is not yet clear how many will be built. LNG storage facilities will also continue to be important in meeting peak demand needs of local utilities and as a way to store gas until needed. In addition, several niche markets, such as vehicular fuel and as an alternative to propane for facilities off the pipeline grid, demand gas in the form of LNG whether from domestic or foreign sources.

LNG is natural gas that has been cooled to about minus 260 degrees Fahrenheit for shipment and/or storage as a liquid. LNG is more compact than the gaseous equivalent with a volumetric difference of approximately 610 to 1. LNG's physical qualities allow industry participants to overcome certain limitations inherent in the transportation and storage of natural gas. The advantages of LNG allow long-distance transport of LNG by ship across oceans to markets such as the United States and local distribution by truck onshore. The storage advantages allow for use of LNG to meet peak demand needs and in certain niche markets such as propane replacement.

Liquefaction also provides the opportunity to store natural gas for use during high demand periods in areas where geologic conditions are not suitable for developing underground storage facilities. For example, in New England and the coastal areas of the Middle Atlantic states, where underground storage is lacking, LNG is a critical part of the region's supply during cold snaps. In regions where pipeline capacity from supply areas can be very expensive and use is highly seasonal, liquefaction for storage occurs during off-peak periods in order to reduce expensive pipeline capacity commitments during peak periods.

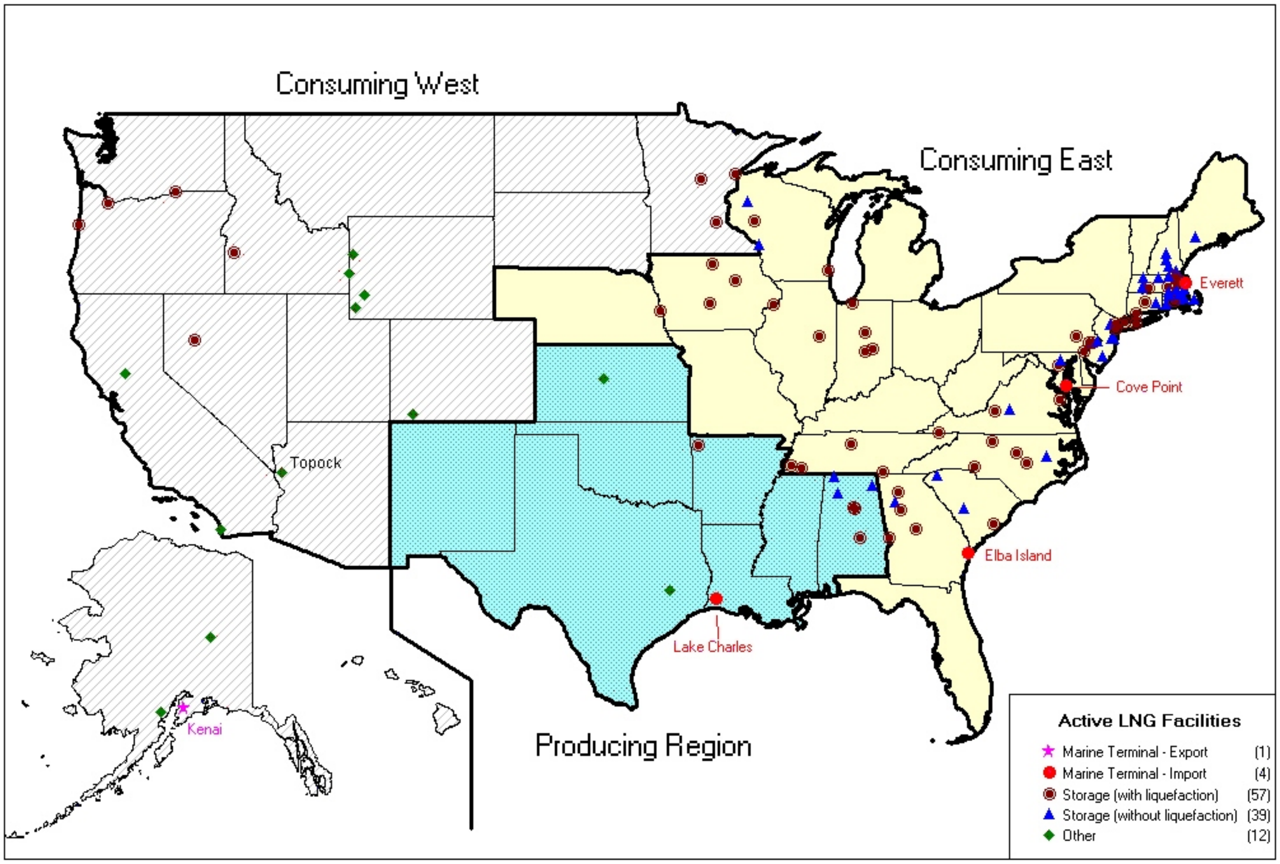
Future developments in regard to LNG's role in the U.S. energy industry will likely depend in part on the public's perception of the need for additional natural gas supplies and the safety and reliability of LNG operations compared with other fuel choices. LNG facilities throughout the world generally have had an excellent safety record. In November 2002, Congress enacted The Maritime Transportation Security Act of 2002 (S. 1214), which expands the Coast Guard's role in providing port security concerning a variety of maritime activities, including the transportation by tanker of oil, compressed natural gas, and LNG.

This article examines the different aspects of LNG markets and uses, paying particular attention to marine terminal operations, peak-shaving storage facilities, and developing niche markets. Current LNG facilities reflect distinctly different applications of LNG-related technology. Marine terminals receive imports or ship exports of LNG and have on-site storage. Natural gas utilities and interstate pipeline companies own and operate facilities for the liquefaction and storage of pipeline gas for use during high demand periods. Natural gas producers and other companies have built new facilities since the mid 1990s in an attempt to serve new demand for LNG vehicular fuel and other niche markets. Moreover, LNG facilities have the flexibility to participate in several markets at once. For example, LNG is trucked regularly from an import point in Massachusetts for storage at local utilities in the Northeast. Also, at least one local utility in the Midwest liquefies natural gas for vehicular fuel while also storing LNG for use during the winter.

The U.S. LNG Industry

The U.S. LNG industry has experienced periods of both high growth and prolonged downturns. Currently, there are at least 113 active LNG facilities in the United States (Figure 1), including marine terminals, storage facilities, and operations involved in niche markets such as LNG vehicular fuel. Most of these facilities were constructed between 1965-1975, and are dedicated to meeting the storage needs of local utilities. Approximately 55 local utilities own and operate LNG plants as part of their distribution networks. Construction of LNG storage facilities slowed in the latter half of the 1970s. Restructuring of the natural gas industry in the early 1990s

Figure 1. U.S. Liquefied Natural Gas Facilities (September 2002)



Note: Other includes two facilities for vehicular fuel, five serving stranded utilities, and five nitrogen-rejection or co-production units. Map excludes the import facility in Puerto Rico.

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

renewed interest in storage facilities as a way to reduce expensive interstate pipeline capacity requirements, and the construction of several new LNG storage facilities followed.

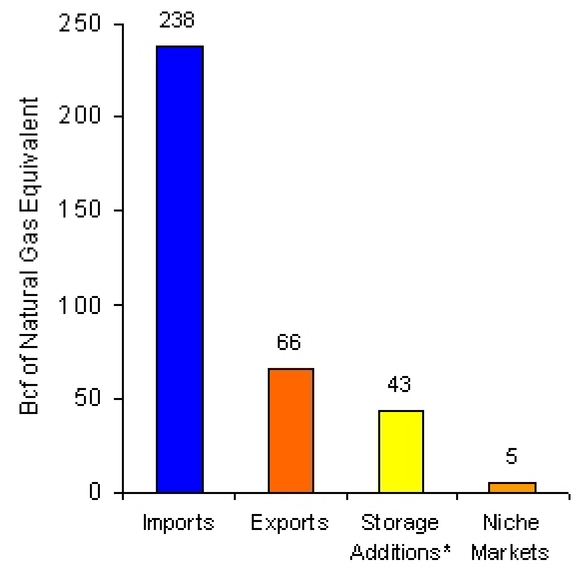
The oldest marine terminal in the United States was constructed in Kenai, Alaska, in 1969 and is still active. The terminal, which is owned by Phillips Petroleum and Marathon Oil, exports LNG to Japan. Imports of LNG into the United States began with the construction by Distrigas of a marine terminal in Everett, Massachusetts, in 1971. The construction of marine terminals at Cove Point, Maryland, and Elba Island, Georgia, followed in 1978. Although operations ceased at the Cove Point and Elba Island terminals in 1980, the construction of one more terminal at Lake Charles, Louisiana, was completed in 1982. The Lake Charles facility operated only a short time before closing, then reopened as an import terminal in 1989. The Cove Point facility eventually reopened in 1995, but to date it has only provided storage services to local utilities. The Elba Island terminal reopened for imports in late 2001 after being mothballed since 1980. Current plans call for all existing import terminals in the Lower 48 States to be operational in 2003 (See Box, "Marine LNG Import Terminals in the Lower 48 States").

The different aspects of the U.S. LNG industry are best characterized in terms of scale. If converted to the natural gas equivalent in cubic feet, LNG imports totaled 238.1 billion cubic feet (Bcf) in 2001 and exports totaled 66.1 Bcf (Figure 2).[1] A similar conversion for the amount of LNG storage additions in 2001 (excluding LNG at marine terminals) was about 42.6 Bcf in 2001. A rough estimate of annual LNG production for use in the niche markets is 5 Bcf in natural gas equivalent. The following sections discuss each of these three LNG applications and facilities.

LNG Marine Terminals

LNG has been imported into the United States for more than three decades and in 2001 represented about 6 percent of total U.S. gas imports.[2] During 2001, 101 tankers arrived at U.S. marine terminals, carrying a total of 238.1 Bcf in natural gas equivalent. The Everett marine terminal received 39 cargoes (a decline of 6 cargoes from the 45 cargoes received in 2000), while Lake Charles received a record 61 cargoes (compared with 56 cargoes in 2000).[3] Elba Island, which reopened in November 2001, received one cargo that had been diverted from Distrigas following the September 11 attacks. LNG imports in 2001 increased by 14.4 Bcf or 6.4 percent from the previous year.[4] This increase lifted LNG import activity near its historic high in 1979, when 252.6 Bcf was received from Algeria.

Figure 2. LNG Volumes in 2001



*Excludes marine terminal storage.
Bcf = Billion cubic feet.
Source: **Imports/Exports**: Department of Energy, Office of Fossil Energy, *Natural Gas Exports and Imports*. **LNG Storage**: Energy Information Administration, Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition." **Niche Markets**: Trade press and industry sources.

Developments in LNG trade throughout the world match or exceed the trend of rising LNG imports to the United States. Both supply and demand are driving plans for expansion of existing facilities and the construction of new facilities. On the supply side is the interest in finding a market for 2,755 to 3,350 trillion cubic feet of stranded

[1]LNG exports to Japan totaled 65.6 Bcf while 465 million cubic feet was exported to Mexico via truck. U.S. Department of Energy, Office of Fossil Energy, *Quarterly Focus: 2001 in Review* (Washington, DC, March 2002).

[2]Energy Information Administration, *Natural Gas Monthly, May 2002* (Washington, DC, June 2002), Table 5.

[3]Department of Energy, Office of Fossil Energy, *Quarterly Focus: 2001 in Review* (Washington, DC, March 2002), pp. viii-xi.

[4]Energy Information Administration, *Natural Gas Monthly*, Table 5. U.S. Department of Energy, Office of Fossil Energy, *Quarterly Focus: 2001 Year in Review* (Washington, DC, March 2002), pp. viii-ix.

natural gas worldwide.[5] On the demand side is the increased use of natural gas worldwide, which coupled with lower costs associated with LNG processing and delivery, is making LNG a cost-competitive supply source to meet gas demand.[6]

Marine Terminal Operations

Operations at an LNG import terminal resemble operations at any large marine terminal handling imports of crude oil or petroleum products, with the LNG being unloaded from ocean-going tankers and stored in above-ground storage tanks. Typically, the LNG is stored only until it can be regasified and injected into the pipeline grid or until it can be trucked directly to customers. The need to process the cargoes quickly, so as to minimize the wait times for the ships and to avoid congestion, in large measure drives the operations at LNG import terminals. Each U.S. import terminal is equipped with storage tanks capable of holding at least one tanker load of LNG, and newer and expanded facilities will typically have a capacity closer to two tanker loads. Large tankers hold up to approximately 130,000 cubic meters of LNG in liquid form, or about 2.8 Bcf of regasified LNG.[7] Although the storage tanks at an LNG marine terminal may function as peak-shaving storage,[8] the principal operation of an import terminal is not for gas storage, but rather for receiving the water-borne LNG imports and then regasifying LNG for shipment via pipelines to customers.

Scheduling for both the arrival of the LNG and the sendout of the regasified product generally is done well in advance to maintain the optimum efficiency at the facility. Multiple sources of supply and robust peak-day deliverability are essential to minimize the potential for short-term inventory imbalances brought about by weather or tanker-scheduling problems.[9] Typically, the regasified LNG is sent out to customers on a routine schedule under a contract that calls for a set daily volume. Consequently, the LNG may be in storage at a marine import terminal for only a few days and, depending on the terms of individual contracts and the time of the year, is seldom held for more than a few months.

In recent years, there has been an increase in the use of more flexible contract provisions that allow customers to sell excess gas, and increased activity through short-term contracts (2 years or less) and spot market purchases. Shippers must obtain import authorization from the U.S. Department of Energy's Office of Fossil Energy to bring LNG into the United States and are responsible for arranging delivery of the LNG to the terminal. In 2001, about 66 percent of the LNG received at the Distrigas facility in Everett, Massachusetts, was imported under long-term contracts, while more than 80 percent of the volumes received at Lake Charles, Louisiana, was under short-term contracts. Spot sales accounted for more than 64 percent of total LNG imports in 2001, up from 51.4 percent in 2000.

After decades with LNG imports considered an insignificant source of gas supplies to the United States, LNG imports have increased by more than 13 times from 18 Bcf in 1995 to nearly 240 Bcf in 2001. A number of factors contributed to this increase in LNG imports, including additional sources of LNG supply to the United States and technological advances that have resulted in lowered costs for liquefaction and shipping. Additionally, higher U.S. natural gas prices in recent years, including the price spike of late 2000 (in which spot prices exceeded $10 per MMBtu) stimulated plans for expansion and new construction. In addition to the expansion plans at the four existing LNG import facilities in the Lower 48 States, more than a dozen proposals for new import facilities have been announced since the beginning of 2001 (Table 2).[10]

[5]Energy Information Administration, *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply* (Washington, DC, December 2001), p. 28.

[6]Energy Information Administration, *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply* (Washington, DC, December 2001), p. 29.

[7]The conversion between cubic meters of LNG and cubic feet of gaseous natural gas accounts for both the difference in units (1 cubic meter = 35.314 cubic feet) and the volumetric difference between gaseous natural gas and LNG in liquid form (approximately 610 to 1).

[8]This has been the function of the Cove Point Terminal since it reopened in 1995 after being closed as an import facility in 1980. Under the terms of its reactivation as an import terminal, the operators of Cove Point are required to provide peak shaving services for the life of the contracts for those existing customers desiring the service.

[9]For example, it may be very advantageous economically for the terminal operator to take an occasional spot cargo requiring the ability to be able to receive a ship out of sequence.

[10]A fifth U.S. import facility is located in Puerto Rico. This facility is not included in the discussion or summary data of this report, which are limited to the 50 states.

Marine LNG Import Terminals in the Lower 48 States

- Everett Terminal – is located in Everett, Massachusetts, near Boston. The facility is the oldest LNG import terminal in the United States and has been in service since it opened in 1971. It is owned by Distrigas, a subsidiary of the Belgium company Tractebel. It has storage capacity of 3.5 billion cubic feet (Bcf) and a sendout capability of 0.44 Bcf per day with an additional 0.09 to 0.10 Bcf per day sendout capacity by truck (Table 1). Planned expansion of capacity at the Everett facility will serve a new merchant power plant located near the terminal.

- Elba Island Terminal – is located in Georgia near Savannah. Following the merger of El Paso and Sonat in 1999, the facility became a subsidiary of El Paso. During 2001, Elba Island was reactivated and received a single cargo late in the year as a part of the testing procedures during the reactivation process, followed by regular shipments in 2002. Elba Island has 4.0 Bcf of storage capacity and will add 3.3 Bcf through its planned expansion. The facility has a peak sendout capacity of 0.675 Bcf per day that will grow to more than 1.0 Bcf per day when the expansion is completed.

- Lake Charles Terminal – is located in Louisiana with access to the Gulf of Mexico. Trunkline LNG, a subsidiary of CMS Energy, owns the facility (although CMS announced in December 2002 an agreement to sell a set of assets including the LNG terminal to Southern Union Panhandle). Based on storage capacity (currently 6.3 Bcf), Lake Charles is the largest LNG import terminal in the United States. Following the completion of its planned expansion, which includes an additional 3 Bcf of storage, it will remain the largest. The expansion also includes an increase in peak sendout capacity from 1.0 Bcf per day to 1.3 Bcf per day. The Lake Charles facility was completed in 1982 but operated only a short time before closing; it reopened in 1989 and has been in operation since that time as an import terminal.

- Cove Point Terminal – is located in Maryland on the Chesapeake Bay. The facility, which was recently sold by Williams to a subsidiary of Dominion Resources, is in the process of being reactivated. The facility is expected to begin receiving tankers in 2003. The facility was completed in 1978 but operated as an import terminal only until 1980. The facility has operated on a limited basis, providing storage services since 1995. Under the terms of the reactivation, Cove Point is required to continue providing peak-shaving services to those customers who desire it for the duration of the contracts. Cove Point has the capability to handle two tankers simultaneously and storage capacity of approximately 5.0 Bcf, which is being expanded to 7.8 Bcf. Following completion of its planned expansion, peak sendout capacity will be more than 1.2 Bcf per day.

Recent LNG proposals include at least five terminals to serve the California markets (to be located either in the United States or in Mexico), a floating semi-mobile offshore facility to be located the Gulf of Mexico but that could be moved to other locations depending on market conditions (see Box, "New LNG Offshore Delivery System"), and three terminals to be constructed in the Bahamas (to serve the Florida market via undersea pipelines). The renewed interest in LNG, particularly in terms of the proposals for new construction, also reflects more long-term issues and concerns. Long-term gas market projections show a significant increase in the use of natural gas to meet energy needs through 2025.[11] Imports of LNG are seen by supporters as a way to address the concern over the ability of domestic supplies and pipeline imports to meet the projected increase in demand.

[11]Energy Information Administration, *Annual Energy Outlook 2003 with Projections to 2025*, DOE/EIA-0383(2003) (Washington, DC, January 2003), p. 77.

Table 1. Existing Capacity and Planned Expansions at LNG Import Terminals in the Lower 48 States, August 2002
(Billion Cubic Feet)

Facility (Owner)	Storage Capacity	Sendout Capacity			2001 Receipts
		Daily		Annual	
		Baseload	Peak		
Everett, MA (Distrigas/Tractebel)					
Existing	3.50	0.435*	0.550	159	90.4
Planned Expansion (2005)	0.85	0.480	0.600	175	--
Total w/Expansion	4.35	0.915	1.150	334	--
Lake Charles,, LA (CMS Trunkline LNG)					
Existing	6.30	0.630	1.000	230	145.1
Planned Expansion (2005)	3.00	0.570	NA	208	--
Total w/Expansion	9.30	1.200	1.300**	438	--
Cove Point, MD (Dominion)					
Existing but inactive	5.00	0.750	1.000	274	Storage only
Planned Expansion (2005)	2.80	0.250	0.320	91	--
Total w/Expansion	7.80	1.000	1.320	365	--
Elba Island, GA (El Paso/ Southern)					
Existing	4.00	0.446	0.675	163	2.6
Planned Expansion (2005)	3.30	0.360	0.540	131	--
Total w/Expansion	7.30	0.806	1.215	294	
Total Existing	18.80	2.256	3.225	826	238.1
Total Planned Expansion	9.95	1.660	--	605	--
Total w/Expansion	28.75	3.916	4.985	1,431	--

*The Everett Terminal has an additional 0.09 to 0.10 Bcf per day of sendout capacity by truck.

**Lake Charles' peak sendout data were provided by CMS Energy.

Note: Totals may not equal sum of components because of independent rounding.

Sources: **Capacity:** Industry trade press, company Internet sites, press releases, FERC filings, and other sources. **2001 Receipts**: U.S. Department of Energy, Office of Fossil Energy.

Table 2. Proposed LNG Import Facilities as of August 2002

Name	Location	Capacity (Bcf)	Owner(s)	Notes
Ocean Cay	Ocean Cay, Bahamas	200	AES	Regasified product to Port Everglades via Ocean Express Pipeline; began taking bids 9-18-01. Connect to FL Gas Transmission.
Mare Island	Northern California	475	Bechtel/Shell	Feasibility study underway (5-02). City of Vallejo conducting independent study of LNG safety issues. Targeted for 2006.
Tampa	Florida	200	BP	Under consideration by BP.
Brownsville	Texas	365	Cheniere	Cheniere holds lease option on site.
Freeport	Texas	365	Cheniere	Feasibility study completed. Negotiations underway for Michael S. Smith to purchase 60% interest in project (12-02).
Sabine Pass	Texas	365	Cheniere	Cheniere holds lease option on site.
California or Baja California	California or Mexico	200	ChevronTexaco	May be located in Baja or offshore California as far north as Los Angeles.
Port Pelican	Offshore Gulf of Mexico	290	ChevronTexaco	Connect to ChevronTexaco pipeline system for delivery to onshore LA.
Hackberry	Louisiana	275	Dynegy	Conversion of underused LPG import terminal. Filed with FERC 5-02. Targeted for 2006.
Altamira	Mexico	475	El Paso/Shell	No supply for US but would reduce US exports to Mexico.
Energy Bridge	Floating Dock Offshore	--	El Paso	Vessel-based system; could be moved to any location favored by economics. Three ships ordered. Targeted for 2005.
Freeport	Freeport Grand Bahama Island	200	El Paso	Regasified product via Seafarer Pipeline to Port of Palm Beach then inland to connect to FL Gas Transmission - 2005.
Rosarito	Baja California, Mexico	250	El Paso/Phillips	Supply to both California in US and Baja California in Mexico.
Freeport	Freeport Grand Bahama Island	250	Enron	Regasified product to Port Everglades via Calypso Pipeline; filed with FERC 7/01.
Saint John	New Brunswick, Canada	275	Irving Oil/Chevron Canada	Would supply some to US markets.
Tijuana	Baja California, Mexico	365	Marathon/ Pertamina	Supply to both California in US and Baja California in Mexico. Planned for 2005.
Los Angeles Harbor	Los Angeles, CA	685	Mitsubishi	Preliminary discussions with LA Dept of Water and Power and SoCal. Being studied by Port Master Plan SubCommittee.
Ensenada	Baja California, Mexico	365	Sempra/CMS	Supply to both California in US and Baja California in Mexico.
Total Capacity (Bcf)		5,600+		

Note: Other import projects are also being considered. This table summarizes most of the major projects proposed as of August 2002.

Source: Industry trade press, company Internet sites, and other sources.

LNG Offshore Delivery Systems

Companies with proposals for new LNG regasification terminals are taking advantage of technological advances to site new LNG facilities offshore. At least two companies, ChevronTexaco and El Paso, are hoping offshore facilities will expedite permitting processes and prove economical. ChevronTexaco has initiated the permitting of its proposed "Port Pelican" project, an LNG regasification terminal located 60 miles off the Louisiana coast in the Gulf of Mexico. The regasification facility, which will include storage tanks, will connect to ChevronTexaco's extensive pipeline infrastructure in the Gulf, initially delivering 800 million cubic feet per day. The regasified gas from the terminal will be delivered to shippers using the national pipeline for transportation to U.S. markets. The facility is expected to be operational in 2006.

El Paso Global LNG has developed a system that allows LNG to be regasified and delivered directly from an ocean-going tanker to an offshore pipeline through use of a mooring system. In May 2002, the company announced its intention to use this new LNG offshore delivery system instead of continuing with plans for three of six planned onshore terminals. Under this system, which combines existing offshore transportation and mooring techniques, LNG is regasified aboard the tanker and then discharged into an undersea pipeline through a buoy that is pulled into a receiving cone connected to the ship. According to El Paso, a typical terminal would have two offloading buoys to ensure a continuous flow of natural gas. The company's first offshore facility is expected to be built off the Gulf Coast and operational by the end of 2005.

Storage

Most commonly, LNG storage facilities in the United States have been constructed solely for use by local utilities. Whereas the storage capacity at marine terminals, which hold LNG imports from tankers, is constantly being recycled in order to manage newly arriving supplies, storage facilities in utilities' service areas often hold LNG for an extended period of time in order to meet peak demand periods. These individual storage facilities have capacity of up to 4 Bcf of natural gas equivalent. Cycling of capacity is rare because owners are typically reserving the supply for the coldest days of the year. Generally, the largest storage facilities liquefy gas from the pipeline grid for the eventual regasification and delivery once again into pipelines. However, numerous storage facilities do not have liquefaction capabilities and receive LNG supplies by truck. These facilities, which are generally much smaller than those with liquefaction capacity, are known as "satellites." These satellite facilities can be further subdivided into those that are connected to the pipeline grid and those that provide year-round (base load) supply to "stranded" local utility systems.[12] A stranded local utility is typically very small and too far from the pipeline grid to be economically connected. For the purposes of this report, satellite LNG storage facilities off the pipeline grid are considered niche market applications.

Receipts and additions from LNG in storage can range widely depending on the severity of winter weather, according to data from Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," for the past several years (1997-2001). Additions and withdrawals from LNG in storage have ranged between 27 Bcf and 52 Bcf per year, excluding operations at marine terminals. In 2001, additions to LNG in storage reached 42.6 Bcf of natural gas equivalent.

LNG facilities offer several advantages over alternative storage options. Because LNG facilities can be located above ground, operators and/or owners have many more opportunities for locating LNG facilities in comparison with traditional underground storage alternatives that depend on underground geological conditions such as depleted reservoirs, aquifers, and salt caverns. Secondly, LNG facilities are often constructed with a higher degree of "deliverability" (the amount of gas the facility can send out under peak conditions relative to stock in inventory) than traditional underground storage facilities.[13] This deliverability provides the opportunity to meet demand spikes, often called "needle peaks." In the Mid-Atlantic

[12]Gas Technology Institute, *World LNG Source Book 2001*, p. V-4.

[13]Research is being conducted to develop the technology necessary for possible underground storage of LNG. On September 30, 2002, the Department of Energy's National Energy Technology Laboratory awarded a cooperative research agreement to Conversion Gas Imports, L.L.C., with the goal of examining and evaluating the potential use of salt caverns for receiving and storing the cargoes of LNG ships. These import terminals, which can be located either on- or offshore, will use salt caverns to replace the cryogenic liquid storage tanks. A successful outcome to such research would further enhance the locational advantages of LNG storage.

region, Baltimore Gas and Electric (BG&E), for example, defines such peak usage periods as those in which the temperature has fallen below 10 degrees Fahrenheit. Propane-air storage is also used by utilities and competes with LNG to meet utility peaking needs (see Box, "Propane-Air Storage vs. LNG Storage").

Stored volumes at LNG facilities account for only a small portion of working gas storage in the country. In fact, LNG storage is usually only a small part of a supply portfolio that includes contracts with rights to pull gas from underground storage fields throughout the winter. However, although the annual volume of LNG stored may represent a small portion of natural gas in storage, LNG often represents a significant part of a company's supply portfolio for peak days. For example, LNG accounted for 32 percent of BG&E's peak-day supply portfolio in 2000 (Figure 3). LNG also provides about a third of peak-day supply requirements for Bay State Gas, a New England-based distributor.[14]

LNG facilities with liquefaction equipment generally are built with design specifications that allow for regasification of about 10 percent of storage capacity for each day of operation. In contrast, the process of filling storage tanks by liquefaction often occurs over the entire refill season. The operator of the LNG facility draws gas from a natural gas pipeline at a rate that will allow for refill of the tank over this period. These operational characteristics highlight the essential advantage of LNG storage: the opportunity to meet the needle peaks that occur during cold snaps with a high degree of deliverability, and at the same time to reduce annual upstream pipeline reservation charges associated with pipeline capacity that would have been necessary if the utility was dependent on receiving the peak supplies as transportation volumes.

Propane-Air Storage vs. LNG Storage

There are several options for local gas utilities who are exploring ways to reduce the costs of serving customers during the peak periods of demand. For example, propane-air storage is a common choice for meeting these short-term needs. Proponents of LNG storage list several benefits of LNG over propane-air storage. First, once regasified, LNG is pipeline-quality gas. As a result, the gas stream from LNG does not have to be blended or mixed in the gas stream in the same way that takes place with propane air.

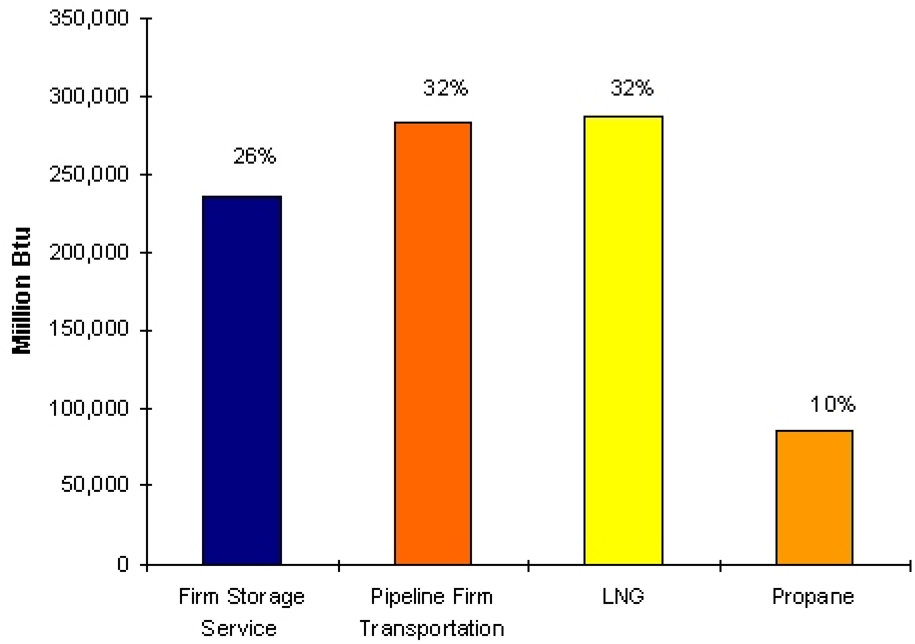
Despite perceived safety concerns, LNG is also arguably safer than propane air. Because propane is heavier than air, it "hangs" low to the ground if leaks occur in storage facilities. This cloud of propane air may ignite. In contrast, LNG is comprised almost entirely of methane, which in gaseous form is lighter than air. As a result, the re-vaporized gas stream floats away into the atmosphere and poses a much lower threat of fire or explosion. (See, Gas Technology Institute, *World LNG Source Book 2001*, "The Role and Economics of LNG-Fed Supplemental Gas Supply," p. V-9.)

Satellite facilities may receive LNG supplies at more irregular intervals than facilities with liquefaction equipment (owing to the capacity of trailers delivering LNG). Additionally, operations at these facilities differ from operations at the larger LNG storage facilities in that operators may regasify from satellite facilities at a much faster rate than 10 percent of storage capacity a day. Satellite facilities often store only enough supplies for 3 days or less. However, as is the case with larger LNG storage facilities with liquefaction equipment, the economic justification of such needle peak-shaving with LNG satellite facilities often rests in analyses of savings from avoided pipeline capacity reservation charges.

An important concept in the calculation of savings from avoided pipeline capacity is the notion of "load factor," which is the amount of pipeline space used throughout the year expressed as a percentage of pipeline space reserved

[14]Estimate provided by Bay State Gas Company officials. For more information on the company's gas supply plan, see: Massachusetts Department of Telecommunications and Energy, *Petition of Bay State Gas Company for approval by the Department of Telecommunications and Energy of a gas supply contract with Distrigas of Massachusetts Corporation*, October 1, 1998. http://www.state.ma.us/dpu/

Figure 3. BG&E's Peak-Day Supply Gas Portfolio, 2000



Source: Maryland Public Service Commission, *Staff Report on the Baltimore Gas and Electric Company's LNG and Propane Facilities*, October 2, 2000.

annually. For example, to meet needle peaks through reserving pipeline space, a utility would pay expensive capacity charges on perhaps a third of its peak-day supply portfolio on an annual basis. If the utility experiences only three or four needle peak days during a normal winter, only a small fraction of the total annual reserved pipeline space would be utilized. A utility without peak-shaving resources will thus have a low load factor and substantially higher transportation costs per MMBtu. The key to improving the utility's load factor and reducing transportation on a MMBtu basis is identifying the alternative sources of supply such as LNG or other storage options to match the characteristics of demand swings on the distribution system.

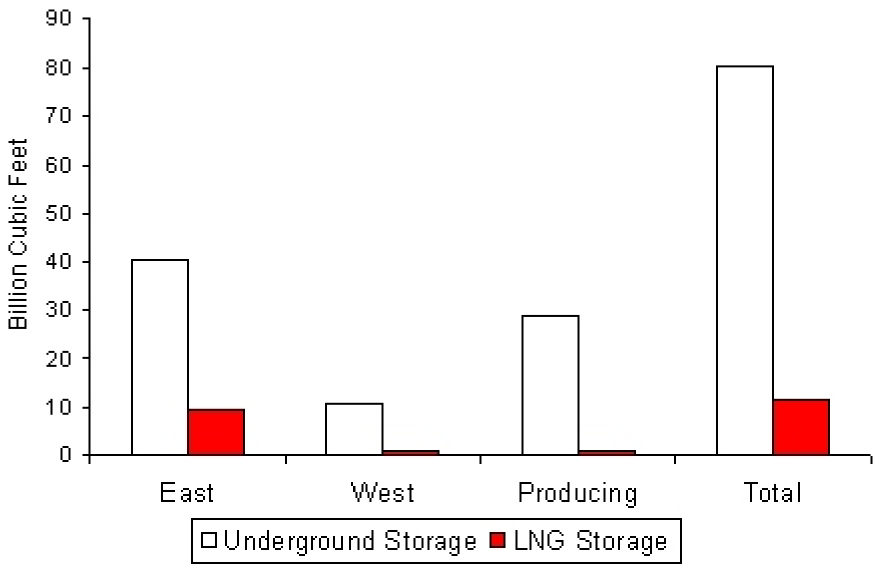
Storage Facilities

Estimated total capacity of LNG storage facilities in the Lower 48 States as of mid 2001 (excluding marine facility storage) is 86 Bcf, with nearly 82 percent of the total in the Consuming East Region.[15] The Consuming West Region accounts for 14 percent of the LNG storage capacity, while the Producing Region accounts for only 4 percent. Working gas capacity of LNG facilities remains a very small portion of the Lower 48 storage capacity at just over 2 percent of overall capacity.

Despite the relatively low amount of LNG storage capacity, the high daily deliverability of LNG facilities

[15]The storage regions identified in this report generally correspond with regions for underground natural gas storage in EIA's *Weekly Natural Gas Storage Report,* as shown in Figure 1.

Figure 4. Daily Deliverability of LNG Storage and Underground Storage Facilities, 2001



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

makes them an important source of fuel during winter cold snaps. LNG facilities can deliver up to about 11 Bcf/day, or the equivalent of 14 percent of underground storage deliverability (Figure 4). In the Consuming East Region, LNG facilities amount to 23 percent of underground storage deliverability during a peak day. The deliverability of facilities in the Consuming West Region is about 1.1 Bcf/d or about 10 percent of underground storage deliverability.

Most LNG storage facilities are owned by distributors and are located within the local utility's service area. An important feature of the facilities is that they provide reliability to their distribution system and operational flexibility during times of high demand. State commissions regulate the operations of these facilities as part of utilities' integrated distribution systems. Interstate pipeline companies also own and operate LNG facilities (15) in much the same way as they own and operate underground storage facilities as part of their integrated systems. FERC regulates these facilities, requiring open access and tariffs for terms and conditions of service. Whether an interstate pipeline or local utility owns an LNG facility, the ultimate "end users" of LNG storage historically have been distributors attempting to meet needle peak demand on their system. If an LNG facility is operated by an interstate pipeline company, local distributors will reserve storage capacity and acquire regasification rights according to their supply needs.

Of the 96 LNG storage facilities connected to the pipeline grid, roughly 57 have liquefaction capacity. Most of the remaining 39 storage facilities are located in the Northeast (Figure 1), where many facilities are close enough to the Distrigas import facility to receive LNG by truck. Massachusetts alone accounts for 14 satellite facilities, or roughly 40 percent of all satellite facilities in the United States. In New Jersey, which contains the second highest number of satellites, there are 5 facilities.

Whether or not storage facilities have liquefaction, virtually all of these facilities are connected to the pipeline grid or local utility distribution systems. Their owners elected to construct the storage facilities rather than invest in additional upstream capacity. Interestingly, several facilities in the Northeast with liquefaction equipment have chosen to receive LNG supplies via truckload from the Everett terminal in Massachusetts. The apparent inference here is that Distrigas is able to offer imported LNG at a cheaper price than it would cost the utility-owned storage facilities to liquefy pipeline gas.

Niche Markets and Opportunities

Although still in formative stages, certain niche markets for LNG are developing or have possibilities for future market applications. At present, two of the niche markets appear to be the most promising: LNG as a vehicle fuel or LNG as a replacement fuel for propane, which is commonly used by stranded local distribution companies or at remote or isolated industrial facilities.

Economic incentives in the form of tax breaks or mandates requiring the purchase of alternative-fueled fleet vehicles are the major drivers behind the growth of LNG as a vehicle fuel. However, LNG still represents only a small portion of the alternative fuel market, which is itself only a small portion of the overall market for vehicle fuels. Nationally, in 2001, LNG vehicles accounted for only about 7.6 million gallons (about 0.02 percent) of the more than 366 million gallons of alternative fuels consumed in the United States.[16] At present, California appears to be one of the most likely areas where the necessary regulatory climate, infrastructure, and market may facilitate the development of LNG as a transportation fuel. Nonetheless, a recent study conducted for the California Energy Commission indicates the market will grow to be only about 200,000 gallons per day by 2006. Although this represents a large increase in California demand from about 25,000 gallons per day in 2001, it also demonstrates the extremely small size of the market in comparison with the approximately 40.5 million gallons per day of gasoline consumed in the State.[17]

The one niche market not dependent on incentives or mandates is the propane replacement market. A stranded local utility is typically very small and too far from the pipeline grid to be economically connected. Anecdotal evidence strongly suggests that considerable interest exists in this niche market. On the supply side, suppliers of LNG are attempting to gain new customers by working to convince such small isolated utilities to switch from their existing fuel supply arrangements to LNG. At the same time, some isolated utilities are actively seeking information about making the switch and converting to

Other Niche Opportunities for LNG Operations

Landfill gas—At the present time, only a small number of landfills have LNG production, but there are some 250 U.S. landfill sites producing gas for electric power generation or other uses. (See the paper *Landfill Gas Utilization* on the Internet site of the consulting firm CH IV, http://www.ch-iv.com/cryo/lfg.htm.)

Portable pipeline—A trailer-mounted LNG tank and vaporizer unit that can be located at a temporary site to address a break in a system or to meet demand in special circumstances.

Stranded resources—LNG liquefaction at small isolated fields or even at individual wells. At present, development is undertaken only when economic or other incentives (such as emissions credits) are available or where the gas is used in special processing. One such facility was Quadren near Sacramento, California, which produced a special ultra-high quality LNG for use in industrial testing. The facility was recently acquired by a larger company, and additional wells may now be brought on line with the principal use becoming the alternative vehicle fuel market.

Co-production—Gas moving from production to market can be liquefied to remove impurities (at a nitrogen rejection unit (NRU) within a gas processing plant for example). At NRU facilities, the entire gas stream is liquefied to remove impurities then regasified and sent on as pipeline-quality gas. In a co-production scenario, some of the liquefied gas would be retained and sold into a local or regional LNG market. Currently, only a small number of NRU facilities co-produce LNG (for a few industrial consumers and especially for the vehicle fuel market). However, should the market develop, additional units could also be used for the co-production of LNG. (See the report *California LNG Transportation Fuel Supply and Demand Assessment*, pp. 21-24.)

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[16] Alternative fuels accounted for about 2.6 percent of total transportation fuel consumption in 2001. Energy Information Administration, EIA Web Site, www.eia.doe.gov/cneaf/alternate/page/datatables/table10.html (July 2002).

[17] From a report prepared for the California Energy Commission by USA PRO & Associates, *California LNG Transportation Fuel Supply and Demand Assessment* (January 2002), p. 50. For the gasoline statistics, see http://www.energy.ca.gov/fuels/gasoline/taxable_gasoline.html. Although LNG is not mandated as the replacement fuel, the fact that the South Coast Air Quality Management District is requiring the phase out of diesel buses within the Los Angeles area could mean a significant increase in the use of LNG as a vehicle fuel.

LNG. The market potential for LNG in these instances is largely limited to the Western and Rocky Mountain regions of the country where low population density and the absence of pipeline infrastructure make direct connection of small gas utilities to the pipeline grid impractical. LNG also has replaced propane or other fuels in certain isolated industrial sites such as mineral extraction and forest product facilities. In addition, there are a number of potential niche market opportunities for LNG, but at the present time they depend on special circumstances or are still in either a development or pilot stage (see Box, "Other Niche Opportunities for LNG Operations").

Although the potential for growth, perhaps even significant growth exists in some of the LNG niche markets and applications, it is important to note that they remain quite small relative to the much larger volumes of domestic LNG storage and imported LNG, which in turn represent a small but important part of the much larger U.S. natural gas market. Further, even in optimistic projections for the future, niche markets continue to represent only a small fraction of the total demand for natural gas in the United States.

Conclusion

Growth in the use of LNG technology by the natural gas industry and consumers appears likely. This growth depends on expansion of current facilities and new construction. The need for additional supply sources to meet projected U.S. demand generally coincides with numerous developments in LNG trade on a worldwide basis. These developments include lower liquefaction costs as well as lower shipping costs. LNG storage facilities will also continue to be important in meeting peak demand needs of local utilities and as a way to store gas until needed. In addition, the demand for domestic LNG is expected to increase as companies make inroads into several niche markets such as vehicular fuel and as a replacement to propane for facilities off the pipeline grid.

This article was written by Damien Gaul, an EIA staff economist, and Lillian (Willie) Young, a consultant to EIA. Questions or comments on the contents of this article should be directed to Damien Gaul at damien.gaul@eia.doe.gov or (202) 586-2073.