

Paper #1-10

LIQUEFIED NATURAL GAS (LNG)

Prepared for the
Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Task Group for which this paper was developed or submitted. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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LNG White Paper

1. Introduction

LNG, or liquefied natural gas, comprises a small but important and growing part of the global natural gas market. According to the BP Review of World Energy, LNG consumption in 2009 was 23.5 Bcf/d or 8.2% of total world demand for natural gas. Although 2009 natural gas consumption in its entirety declined by 2.1% in 2009 due to the recession, LNG demand grew by 7.2%. This continues a multi-decadal growth pattern of 6 to 7% per year, far faster than the overall growth in the total natural gas market of 2 to 4%.

The U.S. imported 1.24 Bcf/d in 2009 or approximately 5.2% of the global trade of 23.5 Bcf/d. The inclusion of Canada and Mexico raises that volume to 1.67 Bcf/d for slightly over 7% of the worldwide total. North America is thus having a demonstrable effect on the LNG industry although the rapid expansion of shale gas production has called into question the region's future share of the market.

2. History

Liquefied natural gas is created by cooling natural gas to minus 161 degrees Celsius. At that temperature, natural gas becomes a liquid and the volume drops by a factor of approximately 600. Thus 600 cubic feet of natural gas at room temperature can be contained in a volume of a single cubic foot when liquefied. That decrease in volume allows natural gas to be economically transported by specialized ships to distant markets.

The United States is itself a producer of LNG from its Kenai, Alaska facility which opened in 1969 using gas from the Cook Inlet nearby Anchorage. LNG has been continuously produced from the 200 MMcf/d plant since its inception and sold to its long term contract holders, Tokyo Gas and Tokyo Electric. The United States first imported LNG in 1971 to a regasification terminal in Everett, Massachusetts. The Elba Island, Georgia and Cove Point, Maryland import terminals opened in 1978 while the Lake Charles, Louisiana terminal became commercial in 1982. Due to changes in world markets and prices, the Elba Island and Cove Point terminals ceased operation in 1980 and the Lake Charles project closed shortly after it opened in 1982. The Everett facility, however, protected by downstream contracts in a region that needed LNG for winter peaking demand services, continued to operate.

The inoperative terminals gradually came back into service, first Lake Charles in 1989 followed by Cove Point in 1995. The latter, however, initially served solely as a storage facility, using small scale liquefaction located on site, and did not actively receive import cargoes until 2003. Elba Island was the last of the first wave of terminals to reactivate, when it reinitiated cargo imports in 2001. The four original terminals, plus new projects, enabled import growth to 2.11 Bcf/d in 2007, when LNG provided 3.3% of total U.S. consumption. The last several years have seen lower volumes due to higher global prices that have attracted cargoes to alternate markets in Asia and Europe.

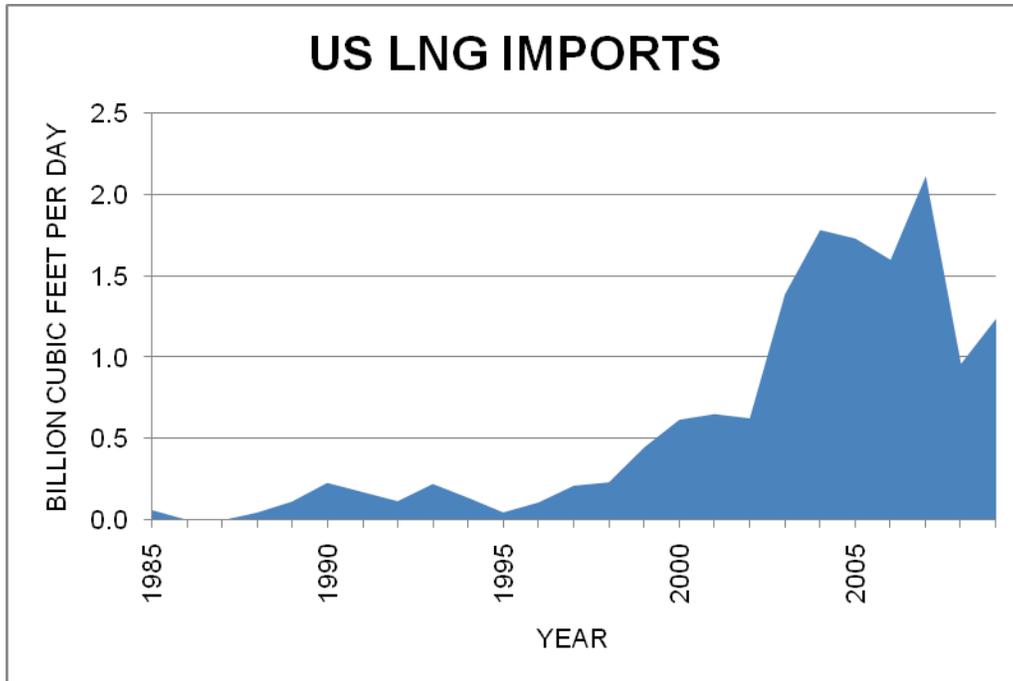


Figure LNG 1, US LNG Imports, Excel file NARD RSTG LNG Whitepaper 12-28-10

The late 1980 - 1990's saw a steady erosion in proved gas reserves in the United States, at the same time as domestic consumption was rising. The reduced reserves to production ratio led to an increased emphasis on drilling unconventional reservoirs, such as coal-bed methane and tight gas sands. Although these reservoirs allowed producers to add an impressive amount of reserves, their low permeability required costlier drilling and production techniques, supporting higher prices for produced natural gas. With the decline in conventional reserves and the increase in the average price of domestic natural gas, energy companies and consultants forecast an increased need for LNG imports. Although the cost to produce, liquefy and transport LNG would be high, it was believed those import costs would most likely be lower than the future marginal cost of U.S. gas.

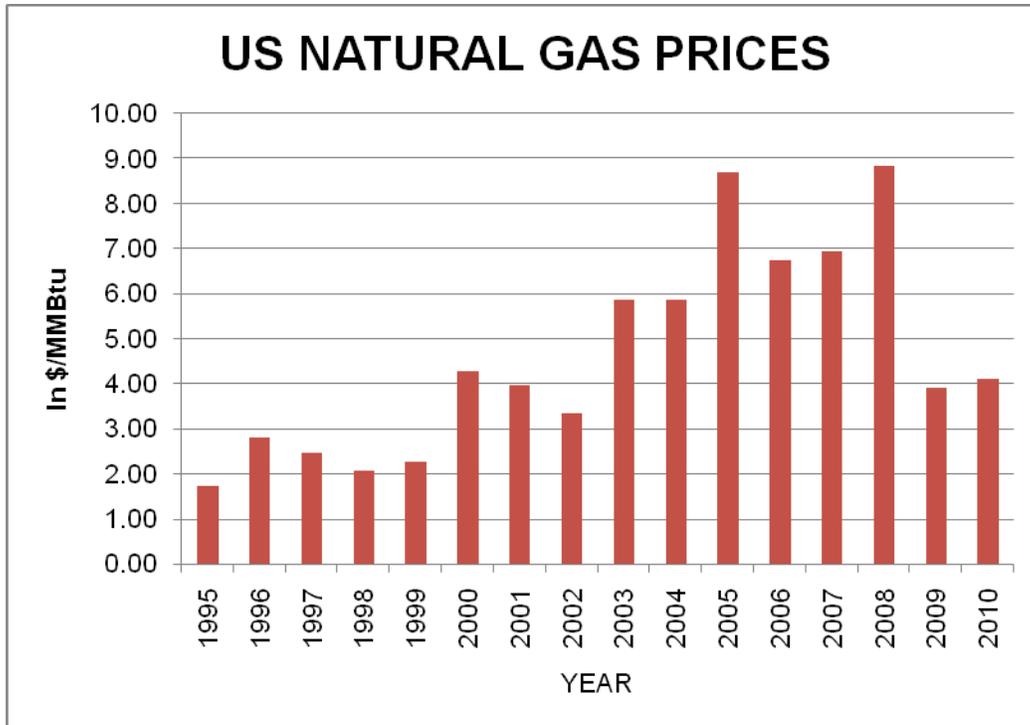


Figure LNG 2, US Natural Gas Prices, Excel file NARD RSTG LNG Whitepaper 12-28-10

As a result of the expected need for LNG imports, expansion activities began at the existing four terminals and multiple firms began development of new regasification facilities. A January 2003 report on LNG by the Energy Information Administration (EIA) cited 11 different domestic regas projects and listed 7 more in the Bahamas, Canada and Mexico that were designed to supply natural gas to U.S. markets.

Development activity continued to expand and a February 16th 2007 report from the Federal Energy Regulatory Commission (FERC) showed five operating U.S. terminals (the original four plus the Excelerate Gulf Gateway facility) and twenty four projects approved for construction; nineteen onshore and five offshore. In addition, nine projects had been formally proposed to the FERC, which has jurisdiction for onshore developments, and five more to the United States Coast Guard, which takes precedence for offshore facilities. Still more proposals were in an evaluation stage in the U.S. and other efforts were active in both Canada and Mexico.

At about this time, however, it became apparent that U.S. proved reserves of natural gas were rapidly growing due to development of tight gas sands and coalbed methane resources. In addition, promising early results from the Barnett shale gas were just becoming public. By 2008 the basic premise that the United States had to import large amounts of LNG to meet projections of rising natural gas demand was called into question. As shown in the chart below produced from Annual Energy Outlooks (AEO) developed by the EIA, expectations for future LNG imports began to plummet by the end of the decade and LNG regasification development efforts began to wind down with a number of projects either suspended or cancelled.

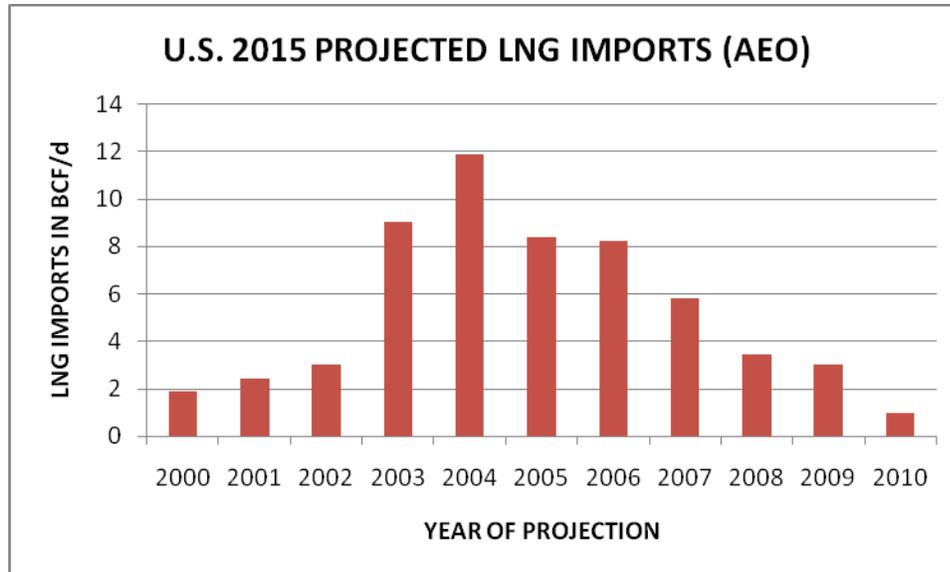


Figure LNG 3, US Projected LNG Imports, Excel file NARD RSTG LNG Whitepaper 12-28-10

3. Safety

A focus on safety pervades the LNG industry. Equipment and procedures are carefully designed to minimize opportunities for error and mis-chance. After literally thousands of cargo transports, there has never been a LNG related fatality onboard a ship.

Safety is aided by multiple layers. International standards require each storage tank to have a primary and secondary containment system. The second system is deliberately redundant and comes into play only if a problem occurs in the primary containment tank.

There is also a wide variety of equipment and control systems associated with each stage of the LNG chain to detect issues before they grow into a problem. Each step of the liquefaction and transfer processes has 'sudden stop' mechanisms to minimize any unplanned deviations from safe procedures.

Safety is aided by inherent characteristics of LNG. While in liquid form, LNG is non-explosive and impossible to light on fire. After vaporization occurs, it requires a fairly high temperature level to ignite, over a 1000 degrees Fahrenheit, and will do so only within a narrow range of mixture with oxygen, from 5 to 15%. If oxygen is less than 5%, a methane plume will not ignite and the same is true if the oxygen level is above 15%. Finally, the vaporized form of LNG is methane, which is lighter than air. When transformed into methane, the gas rises quickly, which limits its potential horizontal coverage.

The University of Texas Center for Energy Economics created an excellent overview of LNG safety in two reports published in 2003, *Introduction to LNG* and *LNG Safety and Security Issues*. Both of these reports can be found at: <http://www.beg.utexas.edu/energyecon/publications.php#research>.

In addition, the Department of Energy has performed a number of studies on LNG safety. Two in particular addressed the potential effects of an LNG spill over water. These can be found at the following website: <http://fossil.energy.gov/programs/oilgas/storage/index.html>.

4. Supply

The U.S. is currently importing LNG from a variety of nations, including Egypt, Nigeria, Norway, Qatar, Trinidad and Yemen. There are currently eighteen countries that produce LNG with a nineteenth, Angola, scheduled to begin production in late 2011.

Besides the eight LNG suppliers mentioned above, additional nations that produce LNG include Algeria, Australia, Brunei, Equatorial Guinea, Indonesia, Libya, Malaysia, Peru, Russia, and the United Arab Emirates. With the number of available providers, there is a substantial degree of security in supply. In fact, LNG contracts are viewed as extremely secure by the energy and investment communities. A breakout of LNG production by nation in 2009 is given below.

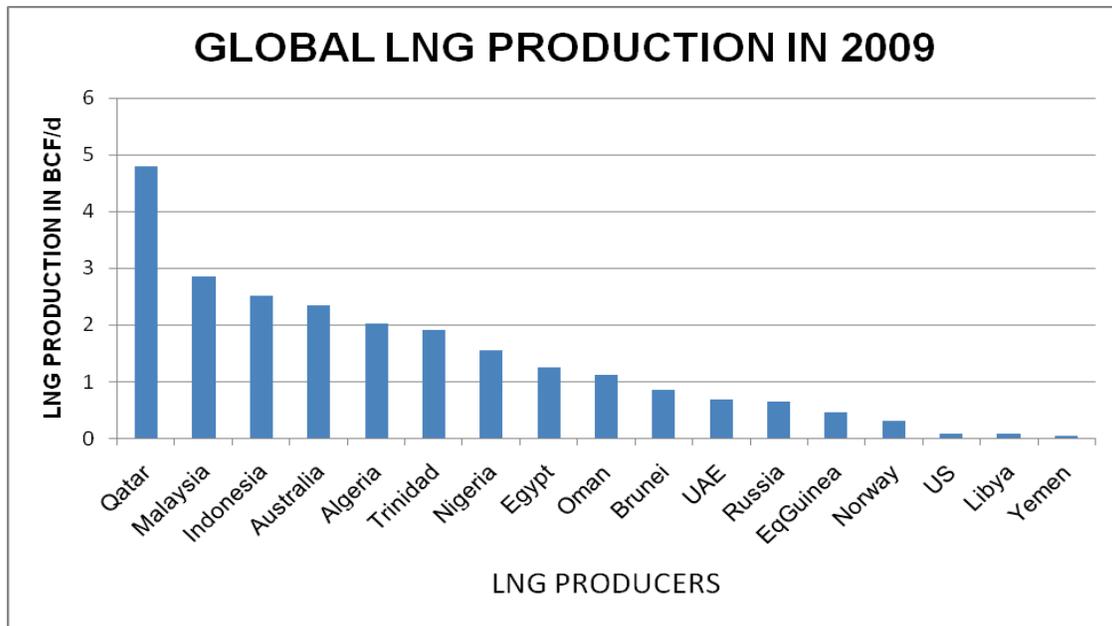


Figure LNG 4, Global LNG Production, Excel file NARD RSTG LNG Whitepaper 7-27-10

As seen in the graph, Qatar is the world's largest producer of LNG. Its share of the global market will expand further as current liquefaction trains, the production systems used to create LNG, expand to full capacity and trains under construction are completed. When all trains are fully operational, Qatar will have the capacity to produce over 10 Bcf/d.

The outlook for new liquefaction capacity is robust. Australia alone has four liquefaction projects under construction and ten eight additional efforts, involving both expansions and new sites, in active development. Many other nations are considering initiating LNG development or creation of new capacity at existing sites. In most cases where the distance to market is more than 1500 miles, and marine access is available, LNG provides the most economical alternative for producers to monetize their reserves.

Although there are many liquefaction projects in development, these efforts have historically relied on long term contracts to make a final investment decision due to the high capital costs of the trade. Recent projects have spent \$5 to \$6 billion dollars to develop all four segments of the supply side of the market: 1) production; 2) liquefaction; 3) shipping; and 4) regasification.

The first segment involves producing the natural gas from wells and gathering it to a central site where the gas stream is processed. The processing stage removes contaminants, such as hydrogen sulfide, carbon dioxide and water, as well as higher value natural gas liquids, which include pentanes and natural gasoline. The latter are usually sold into the global liquids market as a source of ancillary revenue. Indeed, many production efforts for liquefaction projects are based largely on volumes produced from oil or condensate wells wherein the associated natural gas provides a secondary profit flow. For these projects, the cost of most of the production facilities is borne largely on the base of the oil and liquids revenue and the natural gas stream is provided to the liquefaction phase for a very low, and in some cases, almost zero transfer price.

After processing, the gas stream enters the liquefaction plant where it is sequentially cooled by a series of compression/expansion facilities. These modular cooling segments are organized in a linear system that has some visual analogies to linked railroad cars, hence the name 'liquefaction train'. Once the gas is cooled to minus 161 degrees Celsius, the natural gas becomes a liquid and is stored in special cryogenic tanks prior to shipping. Capital investment in this process costs on the order of \$2 billion dollars but the precise value can vary greatly depending on the project's site. In a number of cases, for instance, the developer must build a port and electric power plant due to the remote location of the liquefaction facility.

The extreme cold of the liquefied gas makes it impossible to ship on normal tankers. Conventional steel, in fact, is in danger of fracturing when placed in contact with a liquid at this temperature. Instead, special cryogenic steel or aluminum is used to contain the LNG and then surrounded

by panels of extremely efficient insulation to keep the primary tank walls from direct contact with ambient air temperatures. The resulting ship is very safe but high cost. A normal oil tanker, for instance, might cost \$60 MM while an LNG cargo ship is \$180 - 220 MM or three times as much.

And a single LNG tanker is rarely enough for a specific liquefaction project. The exact number of ships depends on the site of the liquefaction train and the distance to the contracted markets. An LNG tanker normally travels at 18 to 19 knots per hour or about 500 miles per day. Since natural gas pipelines are normally a better option if the distance is less than 1500 miles, most LNG transits are at least a three day journey away and the average one way trip is normally much larger, perhaps 10 days. In order to keep the market smoothly supplied and the storage tanks at the liquefaction plant from hitting their maximum limits, multiple tankers are needed. A trade delivering 0.5 Bcf/d from Nigeria to the U.S. Gulf Coast, for instance, would require six tankers for an approximate cost of \$1.2 billion (6 times \$200 MM). A similar trade from Australia would need twelve vessels for \$2.4 billion which indicates a general focus on selling to closer markets.

Once the LNG reaches the consuming country it must be off-loaded from the tanker as a liquid, which normally takes twelve to twenty four hours. The LNG is then stored in cryogenic tanks until warmed, vaporized, and distributed to the nation's pipeline grid for use. In some cases, the LNG is pumped as a liquid into special tanker trucks and driven to remote secondary storage tanks to provide peaking heating needs for a local utility. The U.S. terminal in Everett, Massachusetts provides a good example of this type of use as it supports a number of satellite tanks in New England. A new regasification terminal is viewed as one of the cheaper parts of the LNG chain as it 'only' costs \$0.5 to \$1.0 billion

The high capital needs of a liquefaction project make it difficult or almost impossible for even the largest companies to fund through their internal cash flow. As a result, most projects issue debt for 70 percent of the total money needed. For a \$6 billion dollar project, the typical debt component would thus be on the order of \$4.2 billion.

For a loan of this magnitude, the debt markets require a high degree of security. Historically, this has been provided by twenty year contracts on 95 to 100% of the designed capacity of the liquefaction plant with the purchases backstopped by firms with the highest quality, frequently national utilities. In the last ten years, a movement towards having very large integrated exploration and production companies backstop the loans has taken place. Only the very largest companies are capable of filling this role, however, due to the long term and high volume of the contracts, many of which have present values in the \$20 to \$30 billion dollar range.

5. Markets

Twenty two countries compete for this LNG production, largely within three regions: Asia, Europe, and North America, the latter defined as Canada, Mexico, and the U.S. In the last few years, South America (Argentina, Brazil, and Chile) have also become important consumers of LNG.

Asia is the region with the largest amount of consumption as many of the nations have little or no domestic gas reserves and the ability to transport natural gas by pipeline is limited by geography. Japan, for instance, imports over 8 Bcf/d each year or roughly one third of the global total. The country has very limited natural gas production, less than three percent of its annual demand, and must import LNG for its natural gas needs. Pipelines are not an economic option for the island nation as the closest countries are also insufficient in natural gas production. The chart below indicates the worldwide consumption of LNG in 2009. As can be seen, the U.S. ranked fifth globally but its current position is likely to be overtaken soon by rapid growth in imports in India, China and the UK.

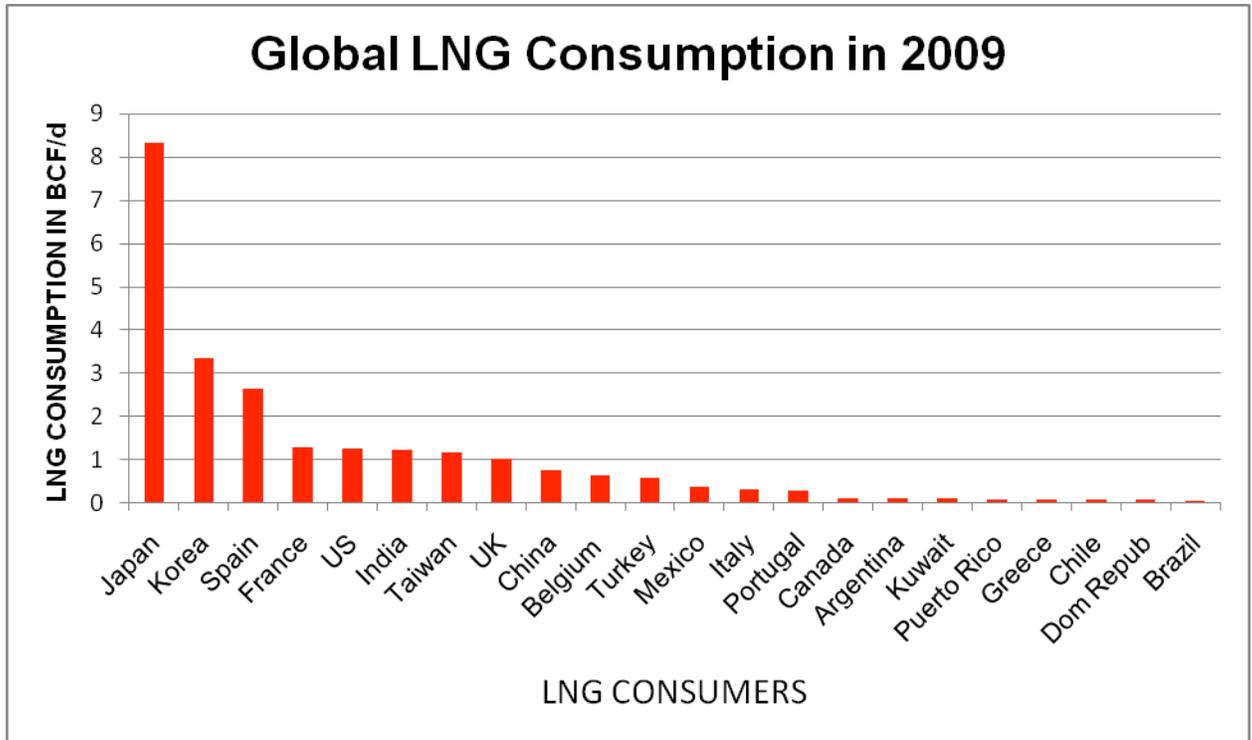


Figure LNG 5, Global LNG Production, Excel file NARD RSTG LNG Whitepaper 12-28-10

The Asian region, comprised of China, India, Japan, Korea and Taiwan, imported 14.7 Bcf/d in 2009 or approximately 63% of the global total. The dominance by this region results from the post-World War II decisions by Japan, Korea and Taiwan, each with limited sources of domestic energy supply, to support their energy needs from multiple fuel types and source locations. These countries thus actively contracted for LNG as a fuel source to provide additional security in case of a disruption in the supply of oil, coal, or uranium.

As a result of the lack of domestic production in these nations, LNG was priced on the basis of an alternative fuel; oil. There is thus no distinct price for natural gas in these markets but merely one linked to oil, which is quite distinct from the U.S. The practice of pricing LNG based on an oil index has extended to more recent Asian LNG importers, including China and India.

Europe is also a net importer of natural gas, largely by pipelines but also through imports of LNG. Spain has, in fact, moved into the third largest position for LNG imports in the past few years and France occupies fourth. Together, Europe consumes over 6.5 Bcf/d or 28% of the world 2009 total and a number of nations are evaluating development of regasification terminals, including Croatia, Germany and Poland.

Similar to Asia, Europe largely prices natural gas on oil indices. The United Kingdom deregulated its energy markets a number of years ago and provides the only major exception to this general rule of oil based pricing. North America is thus almost unique in its widespread use of natural gas that is priced without regard to oil.

The different pricing schemes between the U.S., Asia and Europe, the first based on domestic gas and the others on regional oil indices, results in cross commodity price opportunities. When oil prices are high and U.S. natural gas prices are low, LNG providers prefer to sell spare cargoes to Asia or Europe as they then receive more money than for U.S. deliveries. Of course when the situation is reversed, the focus of the sales side of the market is on the U.S. as higher North American natural gas prices offer the economic return. The different pricing schemes thus draw a market response that constrains price movements in any of the three main regions. The average global price is thus less volatile than it would be if inter-regional trade was curtailed.

6. Regas Terminal and US LNG imports Outlook

The Energy Information Administration (EIA) each year constructs a forecast of U.S. natural gas Supply in their Annual Energy Outlook (AEO) covering long-term US energy supply and demand. Their methodology utilizes a set of linked modules that simultaneously solve for types of energy demand, supply and price across a broad range of industry segments, e.g. residential, industrial, electric generation, and transportation. The approach uses existing laws and regulations and this year's forecast, the AEO 2011, thus excludes any potential effects from federal legislation on greenhouse gas policies or renewable portfolio standards.

Fundamental assumptions incorporated into the model are that the U.S. economy grows at 2.7% per year and that population grows by 0.9% per annum. Growth in electricity use slows to 1.0% per year, in line with the level seen from 2000 to 2008, but well below the 2.4% rate experienced in the prior decade. This decrease in the electric demand growth rate is stated to come from a greater focus on efficiency, both in appliances and industry, and an emphasis on state demand side management programs.

The reference case from this year's forecast shows increased growth in natural gas demand from 2009 to 2020 as compared to AEO 2010. The former projection had consumption barely rise from 61.9 Bcf/d (estimate made in 2009) at the start of the period to the projected demand of 62.0 Bcf/d in 2020. The current outlook includes a much larger domestic gas resource that keeps natural gas prices lower. As a result, demand rises from 62.2 Bcf/d in 2009 (actual 2009 results) to 68.9 Bcf/d in 2020.

After 2020, natural gas demand flattens at the 68 Bcf/d level through 2027 before again starting to slope up, finishing at 72.5 Bcf/d in 2035. This increased demand is located almost entirely within the electric generation sector while the initial growth from 2009 to 2020 largely resides in the industrial segment.

The only AEO 2011 result available currently is the reference case as alternate scenarios will not be released until spring. The chart copied below shows the five AEO 2010 LNG import cases, with the reference case shown as a solid black line, and contrasts those results with the AEO 2011 reference case, which is displayed with the dashed black line. As can be seen, the new import projection is substantially lower than the previous low case (High Oil) due to the significant increases in domestic natural gas reserves and production capacity, both of which result in lower prices throughout the period. These prices compare poorly to international LNG prices which are indexed to oil giving little incentive to ship LNG to North America compared to Asia or Europe.

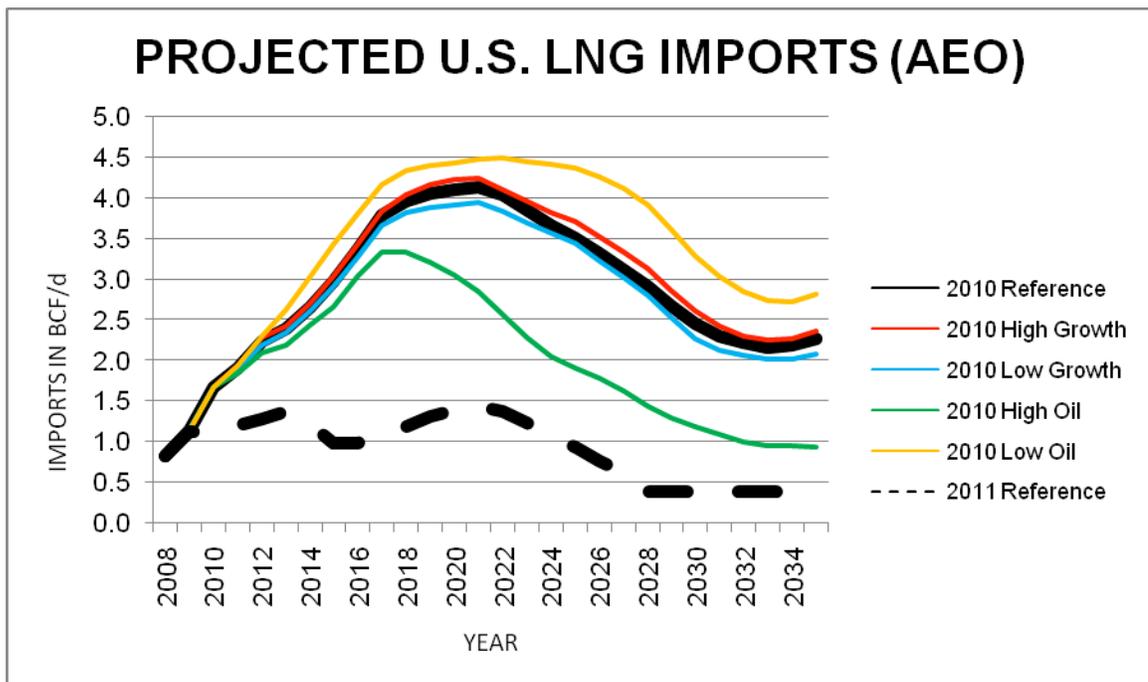


Figure LNG 6, Global LNG Production, Excel file NARD RSTG LNG Whitepaper 12-28-10

The 1.44 Bcf/d maximum import LNG level predicted by the AEO in 2021 can be contrasted with the existing and soon-to-be-completed regasification capacity. As shown in the graphic below, the U.S. will have access to 18.3 Bcf/d of import facilities by 2012. This is over ten times as much as the highest import forecast of 1.44 Bcf/d, indicating the terminals are expected to operate at low levels of utilization through 2035.

Future Capacity = 18.3 Bcf/d

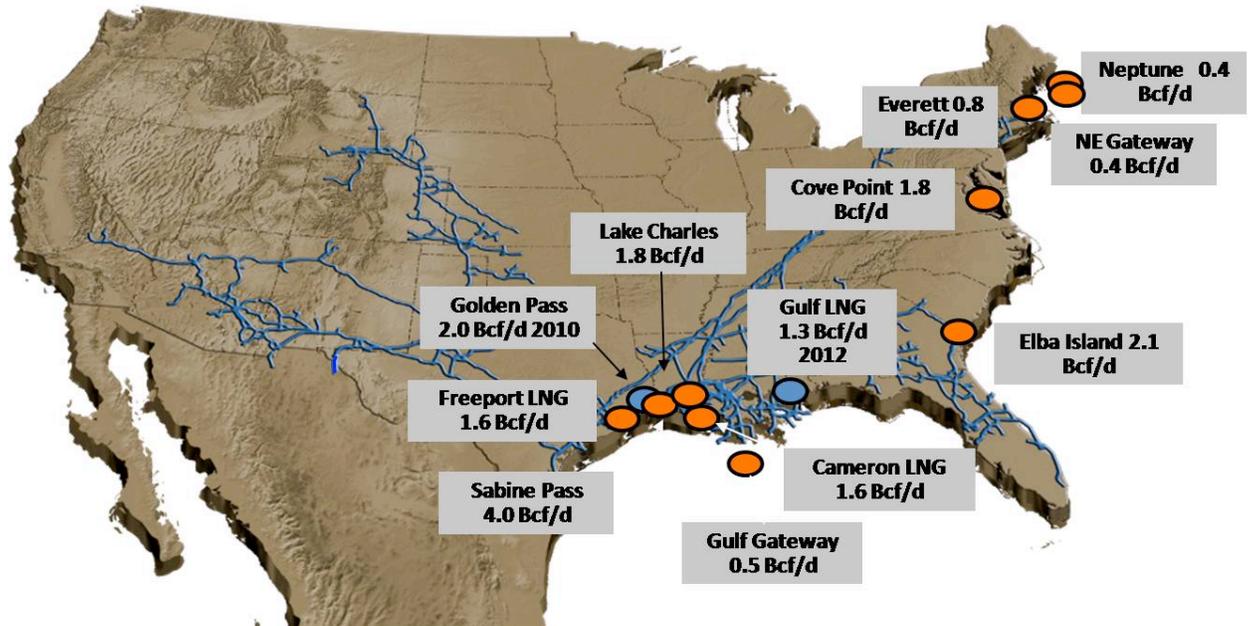


Figure LNG 7, Expected LNG Import Capacity, Excel file NARD RSTG LNG Whitepaper 12-28-2010

Since there will be substantial unutilized capacity in the current AEO 2011 reference case, it does not appear that additional terminals will be required, certainly not in the Gulf Coast or the East Coast. The US West Coast is conspicuous for the absence of LNG terminals but this region is the one most avidly pursuing renewable energy and efficiency standards and thus has the lowest projected growth rate for natural gas demand. Also, the key demand area of Southern California is already supplied by the 1.0 Bcf/d Costa Azul terminal in Ensenada, Mexico, about 40 to 50 miles south of San Diego. A new terminal on the West Coast thus also appears unlikely.

Due to the low utilization rates over the next several decades there should be considerable competition between the facilities for available cargoes. Strong competition of that type could lower revenues to the point that some considered shutting down or entering a mothballed period, similar to what happened in the 1980s. Almost all of the terminals, however, obtained 20 year commitments by highly rated companies for their entire capacity. Given the cost coverage and returns from these long term agreements, the projects should stay open for the entire AEO projection period to 2035 and beyond.

An alternate forecast is provided by the International Energy Agency (IEA). Similar to the EIA, the International Energy Agency creates a projection of energy demand annually, which is called the World Energy Outlook (WEO). Their modeling effort, however, focuses on global energy balances, not just the U.S. as does the EIA's Annual Energy Outlook. Another difference is that they incorporate greenhouse gas policies and associated carbon costs for all OECD (Organization for Economic Cooperation and Development) nations.

As a result of the global focus, much of the results are put in regional terms, e.g. Europe, North America, etc. For gas demand, however, the U.S. is fortunately broken out separately. A

review of the WEO 2010 New Policies Case, which was issued this fall, shows no increase in natural gas consumption in the U.S. across the 2010 to 2035 period that encompasses the projection. It should be noted that this case includes expected changes in regulations and thus differs from the AEO which only incorporates existing regulations and laws. For the U.S., Table 5.2 of the WEO 2010 gives 2008 demand as 64.0 Bcf/d, which then falls due to the 2008-2009 recession, and then slowly rises with only 62.0 Bcf/d of consumption modeled in 2015. Consumption remains at that level to 2025 and then slowly increases to 64.2 Bcf/d in 2035.

The lack of natural gas growth demand in the United States in the World Energy Outlook appears tied to conservation, energy efficiency and a focus on renewable energy sources. The U.S. flatness in natural gas demand appears anomalous, as North America as a whole, including Canada and Mexico, has appreciable growth as do the nations of Europe and Asia. In fact, the U.S. is the only nation or region shown in Table 5.2 without growth in natural gas demand.

Given that the U.S. has no increase in natural gas demand across the entire 25 year period, it would appear logical that the report shows limited increases in LNG imports. The report unfortunately does not explicitly show U.S. projected LNG imports. On Page 192, however, it states “the United States remains a net importer of gas, mainly from Canada, though its imports fall over the projection period.” This statement, combined with a chart (Figure 5.6) that references total North American LNG imports shows 2020 net imports as 34 Bcm or approximately 3.3 Bcf/d. With Mexico committed to imports at three terminals and very active imports at the Canaport facility in New Brunswick, Canada, there appears to be little left over for the U.S.

In 2035, Figure 5.6 shows 67 Bcm of net North American imports or 6.5 Bcf/d. Again, no split is provided for the three countries in question but the limited growth in U.S. demand and the repeated statements that U.S. natural gas prices will be substantially below those in other regions supports a belief that imports into the United States remain low through the entire period.

Existing import terminal capacity, even if underutilized from a purely economic perspective, provides a valuable contribution to security and flexibility of gas supply to the US. In the event of unexpected domestic supply disruptions, due for example to hurricanes or pipeline outages from supply regions, LNG cargoes can quickly be diverted to make up for the shortfall. They can also provide additional seasonal load-balancing capability to supplement the domestic gas storage system. Another advantage is that the addition of supply capability from any source usually has a moderating influence on market prices, thus contributing to maintaining the affordability of natural gas in the US economy. The current focus on domestic gas development should not completely obscure the positive benefits which stem from the existence of such a well-developed LNG import infrastructure, and this country’s openness to LNG trade.

7. North American Liquefaction and Export Potential

The United States was one of the initial exporters of LNG with the launch of the Kenai (Alaska) liquefaction plant in 1969. This 200 MMcf/d project relied on the natural gas reserves in the Cook Inlet, which were far larger than that needed by Anchorage and its associated industries. In order to produce the reserves in a reasonable time period, Phillips and Marathon contracted to sell LNG to Tokyo Gas and Tokyo Electric.

After 41 years of production, Cook Inlet reserves have declined and the output from the facility has fallen from 180 MMcf/d in 2000 to 90 MMcf/d in 2009. The current U.S. Department of Energy permit to export LNG was extended in October 2010 to March 2013 but there is some doubt that another extension will be given unless new reserves are found.

As a result, Alaska has passed legislation that allows companies without production access to tax credits that essentially pay for most of the cost of drilling new wells in the deeper, more expensive portions of the Inlet. Companies with established production had their state tax credits expanded from 20% to 40% in the same piece of legislation.

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Discussion of construction of a pipeline from the northern Alaska Prudhoe Bay reserves, which have 30+ Tcf, has occurred but the high cost of building across Alaska could not be justified economically by the small volume of the current Kenai plant. Instead, development of a 1 to 2 Bcf/d complex would be required to justify the pipeline transport costs. This is not anticipated in either of the two analyses identified, the Annual Energy Outlook and the World Energy Outlook.

A final alternative could be to use the Kenai facility as an LNG import terminal to continue to support Anchorage demand. ConocoPhillips and Marathon are actively evaluating this option at the same time as they have obtained an extension of their export license to 2013.

A second liquefaction project is under development in British Columbia. Galveston LNG, Inc. initially began this effort in 2004 with the concept of bringing LNG into Kitimat from Pacific Basin sources and then sending the supplies to Northeast British Columbia on the existing Pacific Northern Gas Pipeline. After spending a number of years marketing this concept, the developer realized in the fall of 2008 that expanding reserves in the British Columbia (B.C.) Horn River and Montney plays drastically reduced the need and opportunity for LNG imports. Galveston LNG then decided to build a liquefaction plant on the same site to send Horn River and Montney volumes to Pacific Rim countries as LNG.

At this point, the Kitimat LNG project has obtained all necessary federal and provincial permits to function as a liquefaction facility. Galveston LNG recently sold its ownership interest to two large independent oil and gas companies, Apache (51%) and EOG (49%), both of which hold substantial reserves in the Horn River shale gas play. In addition to the project equity, Apache and EOG have signed up to supply the planned production capacity of 700 MMcf/d. On the downstream side, Korea Gas (Kogas), the former gas utility monopoly in South Korea, has entered into a memorandum of understanding (MOU) to purchase up to forty percent of the facility. Mitsubishi has also expressed an interest and other Pacific firms are said to be evaluating the project.

In December 2010, Apache formally applied for an export permit and front end engineering and design (FEED) study is underway. Published articles indicate a cost of approximately \$3.5 billion, which includes the Pacific Trails Pipeline to the Summit Lake connection with Westcoast Pipeline, and the developers are aggressively targeting 2014 as completion date. A final decision to proceed will be made upon completion of the FEED study and will depend on whether the project can achieve binding sales contracts.

U.S. LNG terminal developers are also exploring the concept of liquefaction. Cheniere Energy constructed the 4.0 Bcf/d Sabine Pass terminal in Southwest Louisiana, which has operated at low utilization rate since it began operation in the spring of 2008. Chevron and Total, each holding 1.0 Bcf/d of capacity, have brought in occasional cargoes and Cheniere, who holds the remaining 2.0 Bcf/d of capacity, has also received several tankers. In order to boost revenue, the latter company has re-exported several cargoes over 2010.

In June, 2010 Cheniere declared it was in active discussions on developing a liquefaction facility on the same site which would be able to produce up to 2.6 Bcf/d from four trains. The company engaged Bechtel to perform a FEED study and indicated it anticipated a throughput charge of \$1.40-\$1.70/MMBtu and hoped for a start date in 2015. In August, Cheniere filed for authorization to construct liquefaction with the Federal Energy Regulatory Commission (FERC) and also applied for an export permit from the Department of Energy (DOE). They have subsequently announced MOUs with Morgan Stanley, ENN (China), and Gas Natural (Spain) and the company states it is working with multiple other firms on binding contracts.

In November 2010, Freeport LNG and Macquarie Energy announced plans to construct 1.4 Bcf/d of liquefaction from four trains at the existing 1.65 Bcf/d Freeport LNG terminal in Freeport, Texas. This regasification terminal began operating in June 2008 but, similar to Sabine Pass LNG, it has received only a small number of cargoes and has operated at a very low utilization rate. The two firms would be joint owners in the liquefaction project, which has an

estimated cost of \$2 billion, and 50% of the liquefaction capacity will be initially offered to the current regasification capacity holders of Freeport LNG. Those companies include Dow Chemical, ConocoPhillips, and Macquarie. The remaining 50% of capacity will be marketed by both firms and any capacity unsubscribed by the original capacity holders will also be marketed by the two companies.

A December 2010 pre-NEPA application to the FERC was made and a DOE export permit filing occurred in the same month. The developers have set a target of July 2015 for the start of operations and marketing efforts for suppliers and off-takers are well underway.

Unlike the standard liquefaction developments, which have substantial reserves but no local market, the three North American projects are trying to leave the world's largest natural gas market to sell into countries which price natural gas off oil indices. In the normal development case, the upstream producer cannot place its proved reserves on its financial statements without showing firm contracts to sell into a foreign market given the lack of a domestic outlet. The placing of reserves on the books is itself a substantial advantage to the producing companies as they increase reserve life and lower depreciation expense. Given easy connections to the North American pipeline grid, there is no need for firm sales contracts for Canadian or U.S. producers to gain the advantages cited above.

While a prolonged price differential between North American natural gas prices and world oil indices is projected in both the Annual and World Energy Outlooks, it is not clear if this differential will be strong enough to support a liquefaction project over the normal twenty year recovery period. This is especially true for Europe where the current gas glut has a number of companies, including E.On and Edison, seeking to reduce the ties between natural gas prices and oil indices.

Given the high capital cost of liquefaction capacity, \$2 billion to \$3.5 billion for the above examples, there will be substantial risk for companies that subscribe to this capacity unless they have off-setting agreements. Thus companies that subscribe to liquefaction capacity will seriously consider entering into firm sales contracts as a means of reducing their risk. Although financial hedges could be considered, the length of the contract terms (20 years) and the size of the contemplated volumes make this approach largely infeasible. The financial markets are simply too ill-liquid in the outer years to provide the protection needed.

As a result, the AEO 2011 does not anticipate a U.S. liquefaction plant will be constructed through 2035. The WEO 2010 report is not as clear as it refers to 'net' LNG traffic but the failure to mention North American liquefaction appears to indicate a similar prediction, based on the information available at the time these forecasts were made. However, if commercial entities are willing to shoulder the risks identified and can obtain financial backing, some or all of these projects could go ahead over the next decade. As profiled here, if all proceed they would require up to 4.7 bcf/day of gas supply from US and Canadian sources. In the overall context of North American gas supply, it is likely that such quantities of gas could be made available without disrupting US and Canadian domestic supply/demand balances. The risks for these projects are thus commercial and financial rather than linked to any concerns over feed gas supply.

8. Summary

The global LNG market provided slightly over 8 percent of worldwide natural gas demand in 2009, around 23.5 Bcf/d. LNG production and consumption is growing at a rate of 7 percent per year, which is twice as much as the general natural gas market.

Despite the rapid growth of LNG, the U.S. is expected to import at very low levels over the next several decades as increasing domestic production, led by shale gas, should keep North American prices below the Asian and European markets, which are tied to oil indices. As a result, the 18.3 Bcf/d of terminal regas capacity is expected to operate at low load factors.

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Although an argument can be made for new U.S. liquefaction projects due to regional price differentials, neither study reviewed anticipates these types of projects going forward.