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OFFSHORE LNG RECEIVING TERMINALS

A Briefing Paper from the

GUIDE TO COMMERCIAL FRAMEWORKS FOR LNG IN NORTH AMERICA

A Research and Public Education Consortium

CENTER FOR ENERGY ECONOMICS

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Introduction

This briefing paper is the fourth in a series of articles that describe the liquefied natural gas (LNG) industry and the growing role LNG may play in the US energy future. The first, ***Introduction to LNG***, briefly touches on many of the topics relating to the LNG industry. The second and third papers, ***LNG Safety and Security*** and ***The Role of LNG in North American Natural Gas Supply and Demand***, address details on LNG operations and the North American natural gas marketplace. All of these reports, with supplemental information, are compiled into a complete online fact book, ***Guide to LNG in North America***, available at www.beg.utexas.edu/energyecon/lng.

Domestic natural gas production has not met natural gas demand in the United States for decades. Most forecasts of domestic production and demand show continued pipeline imports from Canada, future deliveries of natural gas from Alaska and an increase in natural gas imports in the form of liquefied natural gas (LNG). Some scenarios show limitations in the ability to grow or even maintain natural gas imports from Canada. Even with the planned construction of new pipelines to deliver Alaskan and Canadian Arctic

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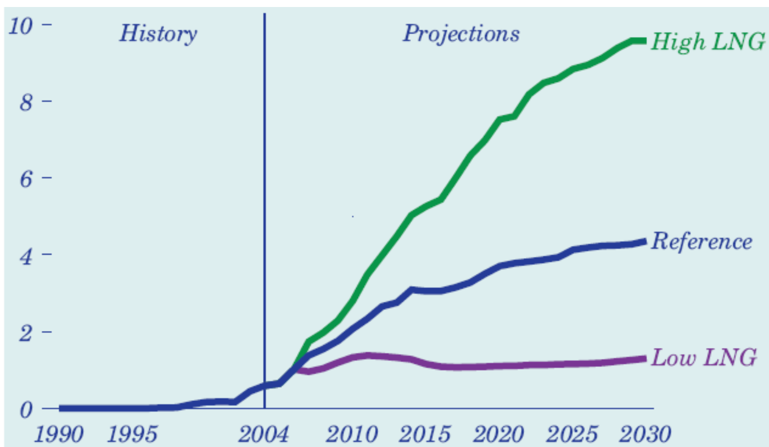
[1] This report was prepared by the Center for Energy Economics (CEE) through a research and public education consortium, ***Commercial Frameworks for LNG in North America***. Sponsors of the consortium are BG North America, BP Gas Americas, Cheniere Energy, Chevron Global Gas, ConocoPhillips Worldwide LNG, Dominion, El Paso Corporation, ExxonMobil Gas & Power Marketing Company, Freeport LNG Development, L.P., Sempra Global and SUEZ LNG NA. The U.S. Department of Energy-Office of Fossil Energy provided critical support and the Ministry of Energy and Industry, Trinidad & Tobago and Nigerian National Petroleum Corporation (NNPC) participate as observers. The report was prepared by Dr. Mariano Gurfinkel, Project Manager and Associate Head of CEE; Dr. Michelle Michot Foss, Chief Energy Economist and Head of CEE; Mr. Dmitry Volkov, Energy Analyst, CEE; and Mr. Fisoye Delano, Group General Manager of NNPC (then a Senior Researcher at CEE). The views expressed in this paper are those of the authors and not necessarily those of the University of Texas at Austin. Peer reviews were provided by a number of outside experts and organizations.

gas to the lower 48, a significant shortfall of natural gas is predicted. This indicates that increased natural gas demand will mostly be met by additional imports of LNG. Future forecasts of LNG demand, such as those of the US Energy Information Administration, illustrate the importance of price, availability of infrastructure and thus the uncertainty that surrounds future volumes of imports. As can be seen below in Figure 1, LNG demand uncertainty as estimated by the US EIA is almost an order of magnitude for the year 2030.

Figure 1 US Energy Information Administration Scenarios for Net LNG imports to the US (Source DOE EIA Annual Energy Outlook 2006)



Rising demand for LNG creates the incentive for new import facilities given that existing facilities, even considering planned expansions, are not projected to provide enough capacity to handle the eventual volumes of imported LNG. Additionally, diversity of geographic locations and proximity to demand centers create added incentives for new terminals. Currently, there are many projects under consideration for construction of onshore and offshore LNG receiving terminals in North America, some of which have received regulatory approval[2] or are in the process of doing so. Most, however, have yet to enter the approval process or are under review for regulatory approval.

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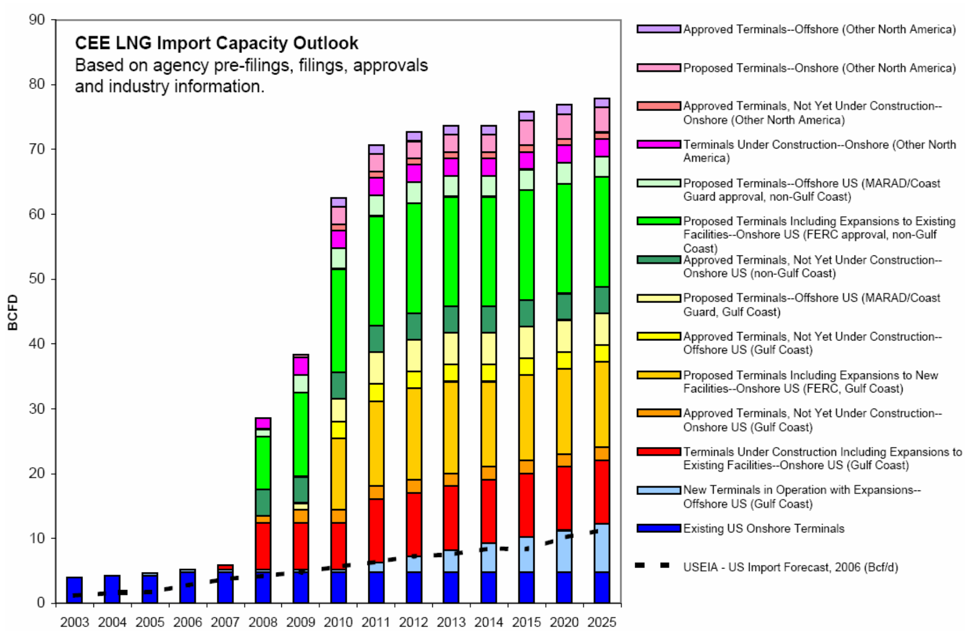
[2] The reader can link to the Federal Energy Regulatory Commission (FERC) for an overview of the status of North American LNG projects, http://www.ferc.gov/industries/lng.asp.

The regulatory process for siting LNG receiving terminals is an important factor controlling the design, construction and eventual commercial viability of the new infrastructure. All new LNG receiving terminals, even those with regulatory approvals, operate subject to market conditions. Given the competitive, market driven process for new LNG import terminal receiving capacity and the competition for LNG supplies, it is unlikely that all of the potential import capacity that is under discussion, or planned or proposed, will be developed. Moreover, scenarios in which spare LNG terminal capacity is generated may prove likely. Much like the case in oil and other commodity markets, spare capacity may prove beneficial to consumers since it not only provides increased energy security, but also provides increased competition and a wider array of choices and options for delivering LNG to the United States and North America.

The development of import terminals is in itself a competitive process. As mentioned above, many more terminals are under consideration than will be built. This implies that significant signaling by project developers will likely take place in order to avoid overbuilding terminals.

Figure 2 Comparison of Estimated Additional Capacity from Proposed Offshore LNG Terminals and LNG Import Forecast



Onshore facilities have been proposed in most coastal areas of the United States. However, the US Gulf Coast region is where most new onshore facilities have received approval from the Federal Energy Regulatory Commission or FERC, which has regulatory authority for onshore LNG import facilities. Eight out of nine new approved onshore LNG facilities are located along the Gulf Coast.

The option of developing offshore LNG import receiving and regasification capacity raises both opportunities and challenges. LNG receiving terminals have been built mostly on-shore despite the long history of offshore crude oil receiving facilities around the world[3]. In some locations, an offshore receiving terminal may provide a better alternative due to the use of existing offshore facilities and pipelines, easier access for LNG tankers, and more flexibility to adapt to regulated exclusion zones. There are also some possible drawbacks or hurdles such as limited or distant access to natural gas distribution pipelines, lack of onshore services and in most instances, higher initial investments. On key issue is that offshore LNG facilities are "new". As noted above, crude oil has been produced, stored and transported from offshore fields for many decades. Advanced technology, marine operations know how, safety and environmental protection, and onshore support for construction and maintenance are among the many aspects of accumulated experience that can be and are being borrowed from the crude oil industry in support of offshore LNG development. However, the newness of offshore LNG introduces new complexities, costs, and questions about feasibility. By incorporating proven technologies, technical and economic uncertainty is reduced and some of the resulting risks mitigated.

Along the US Gulf Coast, offshore LNG facilities can be developed to connect with available infrastructure, such as subsea pipeline networks, that may not be fully utilized. The US Gulf Coast hosts a vast natural gas pipeline network

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[3] In the United States, the legal framework for LNG deepwater ports is very recent, only dating to 2002 with the passage of the Maritime Transportation Security Act, which amended the Deepwater Port Act of 1974.

that was built to serve shallow water exploration and production activity. Pipelines in areas where this domestic activity is very mature and declining—mainly the US Gulf of Mexico “shelf”—have spare capacity available to carry natural gas to shore from offshore facilities. Gulf Coast offshore LNG facilities can be placed so as to serve more than one market area and can provide convenient alternatives for LNG shipping.

A number of distinct challenges affect offshore LNG locations. Marine operations for offshore LNG facilities present new and different hazards and design specifications that must be dealt with and accommodated. This can increase the cost associated with LNG import operations. If subsea pipeline connections must be developed, additional design and cost considerations are introduced. Offshore LNG operations also face a different jurisdictional environment under the Deepwater Port Act (DWPA). The federal authority for the DWPA is the Maritime Administration (MARAD) with the US Coast Guard (USCG) as the lead agency for carrying out the National Environmental Policy Act (NEPA) responsibilities specifically and as implementer for regulatory processes in general. The governors of coastal states participate in the decision making process, introducing many considerations with respect to timing and other issues. In fact, the DWPA permits the designation of additional states beyond the state off whose coastline the terminal is proposed, to be designated “adjacent coastal state” and participate in the review process, including giving that state a gubernatorial veto. Under the DWPA, a governor’s veto cannot be appealed.

There are diverse approaches to offshore LNG receiving and regasification terminals. The LNG offshore import terminal design depends on many factors such as: the use of existing infrastructure (platforms, underwater pipelines), the constraints imposed by water depth (shallow versus deep), the need for local LNG storage facilities, and the opportunities for use of seawater to provide heat for the regasification process.

Most proposed offshore LNG designs incorporate technologies that have been proven in other applications such as for onshore LNG receiving terminals, offshore oil and natural gas production platforms, and offshore crude oil receiving and storage terminals. By using proven technologies, technical and economic uncertainty is reduced and the resulting risks mitigated.

This document presents an overview of the need for new LNG import facilities and information on current issues regarding offshore LNG receiving terminals, differences between offshore and onshore terminals and an overview of some of the different designs that are being considered. This document does not address all of the possible commercial issues associated with the many different design schemes under consideration for offshore LNG facilities. In addition, the focus for this document remains on North American based operations; as with onshore LNG, offshore LNG strategies are under consideration in many other parts of the world.

A key question for the interested public is: *when does it make sense to "go offshore" with respect to development of new LNG import receiving capacity?* This document represents an attempt to address that question by providing an independent and thorough examination of offshore LNG strategies that are under consideration and under development, some of the cost and economic factors associated with these strategies, and some of the many issues and questions that apply to offshore LNG developments.

Overview of LNG Marine Import Terminals in North America

Currently, there are five operating LNG import terminals in the United States with a total peak "sendout" capacity (meaning the amount of natural gas that can be delivered from the LNG import terminal) of about 4.9 billion cubic feet per day (Bcf/d) (see Table 3). Planned expansions, when completed, will account for another roughly 2.3 Bcf/d of sendout capacity. Of the existing five LNG import terminals, the facility most recently brought into operation is also the only one located offshore (The Gulf Gateway Energy Bridge[4]).

[4] LNG regasification is performed on the novel LNG tanker.

As of July 2006, 17 new LNG import terminals have received approval from the two responsible US agencies: fifteen onshore (approved by the FERC[5]) and two offshore (approved by MARAD[6]/US Coast Guard[7]). This is constantly updated as the responsible agencies proceed with the processing of license applications. Additionally, six more North American terminals have received approval by the corresponding regulatory agencies in Canada (three) and in Mexico (three). There are 22 additional LNG import terminals proposed and at least 20 more under consideration[8]. The sum of existing, approved and proposed capacity would imply a potential total peak sendout capacity of more than 46 Bcf/d which would be equivalent to approximately 75 percent of 2004 US natural gas demand[9] (see Figure 2 above). As mentioned earlier, the process of proposing, obtaining regulatory approval, financing, designing, constructing, operating, and achieving commercial success with regard to procurement of LNG cargos is a long and complex process. Only a portion of the potential new facilities will be built and of those only a few will achieve economic success.

Strong price signals for natural gas[10] and projected rise in LNG imports has prompted companies to explore sites for new LNG import facilities, both onshore and offshore. This is the result of a combination of factors such as availability of infrastructure and the project approval process. Many arguments can be made to favor offshore locations such as:

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[5] The FERC has approved two pipelines that would bring natural gas from LNG terminals in the Bahamas to the US mainland. While there were originally three terminals proposed for the Bahamas, two of the projects merged and so now only two remain. One received governmental approval in August 2006, and the other is still awaiting authorization from the Bahamian government.

[6] http://www.marad.dot.gov/

[7] http://www.uscg.mil/USCG.shtm

[8] Federal Energy Regulatory Commission (FERC), http://www.ferc.gov/industries/lng/indus-act/terminals/exist-prop-lng.pdf

[9] Energy Information Administration (EIA), http://www.eia.doe.gov/ reports 2004 natural gas annual demand of 22.4 Tcf in the 2006 Annual Energy Outlook. That is equivalent to 61.4 Bcf daily.

[10] However, current competition for LNG cargoes from other markets has in some cases driven LNG prices to levels above what can be economically brought into the US.

- Potentially lower costs;
- Clearer permitting process;
- Reduction of construction and delivery risks;
- Reduced safety, security and navigational risks;
- Increased terminal availability;
- Flexibility of location selection; and
- Simplified decommissioning.

Whether any or all of these factors prove to be in favor of offshore LNG terminals is subject to intensive design, feasibility, and commercial review.

Not all proposed or planned projects will receive approval and much less will eventually be built. And even if built, new LNG terminals may not necessarily be used to full capacity. A similar situation arose with the existing terminals built during the 1970s when most were not used to capacity and even mothballed until being brought back into service recently. Most of the projects under consideration propose to start operation before the end of the decade or early in the coming decade. If the timetables are kept, this will likely result in spare LNG import receiving capacity much like there is currently.

LNG import capacity does not necessarily match short term LNG demand or LNG availability. Moreover, spare capacity in the aggregate may not be equivalent to spare regional capacity due to regional differences in demand. The decision to move forward with construction (after approval) is based on economics over the life of the projects, where markets are found for the volumes of LNG imported and facilities are used accordingly. Having projects ready for construction or built and having spare capacity presents an "option value" in the case of increased natural gas demand. The option value stems from the ability to utilize some LNG import terminal storage and regasification capacity if needed; that is, the option will not be exercised until the right economic parameters are achieved (such as peak day demand during summer or winter). Much like the case for oil or electric power, spare capacity for LNG not only provides increased energy security but also provides increased competition for delivering LNG to the United States. Option value associated with spare LNG import receiving capacity is not without risk. Developers, operators, and large customers of these facilities must engage in appropriate risk management practices in order to ensure long term commercial viability and success.

The notion that not all LNG import projects will be built is confirmed by the fact that to date, of the approved locations, only a few have broken ground. Projections for LNG imports by the US Energy Information Administration range from two to almost 10 Tcf per year, as can be seen in Figure 1. That is equivalent to imports anywhere between today's level of demand and enough to fill all planned expansions and a limited number of new terminals with an aggregate capacity of 7 Bcf of sendout capacity per day. US demand for LNG further into the future is likely to grow as natural declines in domestic production continue apace and as natural gas continues to satisfy preferences for safe, clean, affordable energy.

In addition to volumetric risk associated with LNG import terminal capacity, other issues need to be considered such as natural gas pipeline takeaway capacity, distance to demand centers, redundancy of infrastructure (to provide energy security and infrastructure security, for example in response to weather related outages), reliability of domestic natural gas production and deliveries, economic viability of increased production from new non-conventional domestic natural gas resources, to name a few. These factors indicate that an appropriate mix of onshore and offshore LNG terminals will result to provide adequate LNG import capacity.

LNG currently accounts for about two percent of US natural gas supply. The Energy Information Administration (EIA) of the US Department of Energy (US DOE) forecasts a shortfall in US natural gas supply of about 7.5 trillion cubic feet (Tcf) by 2025.[11] LNG imports are projected to reach about 13.1 billion cubic feet per day (Bcf/d) or 4.8 Tcf a year by 2025 and would account for about 15 percent of total US consumption (pipeline imports of natural gas from Canada would comprise the remainder of total natural gas imports required to balance the US market). A level of LNG imports of 4.8 Tcf would be nearly an order of magnitude greater than current volumes of imported LNG. Growing demand for natural gas as well as challenges in maintaining and replacing domestic production of natural gas are the major factors driving US EIA and other long term outlooks for US LNG imports.

In addition to the US, LNG is expected to play an important role in Mexico's energy supply portfolio. New LNG onshore receiving terminals are under construction in Altamira (recently completed), Tamaulipas state and in Baja California. Additional onshore projects are under discussion for both the east and west coasts of Mexico. Two offshore projects are proposed on Mexico's Pacific coast.

LNG facilities also are under construction or review in Atlantic and Pacific Canadian provinces. Disappointing results from Canadian offshore natural gas exploration coupled with supply-demand signals in the northeastern US[12] have stimulated considerable discussion and effort to locate LNG receiving capacity in eastern Canada. An onshore receiving terminal will soon be under construction in New Brunswick and other onshore projects are under regulatory review. No offshore LNG receiving facilities have been publicly announced for Atlantic Canadian provinces.

Law and Regulation for Offshore LNG in the United States

Until the passage of the Deepwater Port Act of 1974 (DWPA[13]) the regulatory process for offshore activities in federal waters did not clearly define the licensing of deepwater ports. Moreover, the original 1974 legislation, as it

[11] See US EIA annual long term outlook, December 2004, www.eia.doe.gov.

[12] The UT-CEE has conducted a major review of natural gas supply demand balances and the role of LNG.

[13] US Code Title 33 Chapter 29

was approved, limited its scope to deepwater ports for oil. It was not until the DWPA was amended by the Maritime Transportation Security Act of 2002 (MTSA[14]), that deepwater ports for natural gas were introduced into the legal framework.

The MTSA authorizes the Secretary of Transportation to serve as the licensing authority responsible for permitting new offshore LNG terminals in US waters[15]. The Secretary of Transportation delegated the responsibility of processing of applications to the United States Coast Guard (USCG) and the US Maritime Administration (MARAD). The USCG was then part of the Department of Transportation and is now part of the Department of Homeland Security. The USCG is the lead agency for compliance with the National Environmental Policy Act and is responsible for navigation safety, engineering and safety standards, and facility inspection. The MARAD is responsible for determining the financial capability of the potential licensees, citizenship and for preparing the project record of decision, and has the ultimate authority to issue or deny the license. The MARAD has 330 days[16] in which to issue or deny a license to an offshore LNG applicant and then it can only issue a license with approvals, either absolute or conditional from the governors of all adjacent coastal states[17].

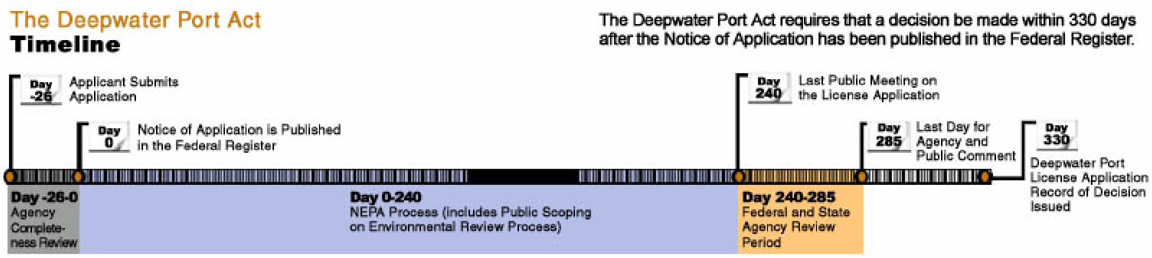
[14] http://www.uscg.mil/hq/g-m/mp/pdf/MTSA.pdf

[15] States have jurisdiction in coastal waters up to 3 miles from the coastline.

[16] 330 days refers to time from the date of publication of the Federal Register notice of a complete application. The analysis of completeness of an application is limited to 21 days after agency receipt of the documents. In some circumstances, during the evaluation of the EIS, more information is required of the applicant. In order to take into account the time waiting for information from the application, the “clock” is stopped during the period.

[17] Adjacent coastal states include the state(s)where the project’s affiliated gas pipeline reaches shore, all states within 15 miles of the port, or any other state designated as such by MARAD/USCG after a request by the state.

Figure 3 Timeline for MARAD Record of Decision for a Deepwater Port License Aplication[18]



The list of applicable laws and executive orders is extensive. A review of this list is presented in every Environmental Impact Statement that is produced for every deepwater port application.[19] Not all of the laws and executive orders are implemented or enforced by the same agency. The role of each agency is briefly summarized in the Memorandum of Understanding on Deepwater Port Licensing (May 2004) in which the commitment and procedure for inter-agency coordination is documented as it refers to deepwater port licenses. Before a license is issued by MARAD[20], other (regulatory) approvals must first be received from:

- US Environmental Protection Agency (EPA) under the Clean Air Act and the Clean Water Act;
- Federal Energy Regulatory Commission (FERC) approval[21] for onshore and offshore interstate natural gas pipelines and ancillary facilities under the Natural Gas Act;
- US Department of Energy (USDOE) authorization for imports of natural gas under the Natural Gas Act[22] as amended;

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[18] Timeline as presented by the MARAD: http://www.marad.dot.gov/dwp/license_reqs/index.asp

[19] A listing of Applicable Laws and Executive Orders can be found in Document USCG-2004-17696-238

[20] Licenses can be issued with observations and additional requirements that must be satisfied.

[21] Approval in the form of a Certificate of Public Convenience and Necessity

[22] Section 3 of the Natural Gas Act of 1938 as amended. US Code Title 15 Chapter 15B

- US Department of Transportation's (USDOT) Pipeline and Hazardous Materials Administration approval concerning pipeline safety;
- US Department of the Interior (USDOI) Minerals Management Service (MMS) determination of fair market rental;
- National Oceanic and Atmospheric Administration (NOAA) approval concerning fisheries impacts;
- US Fish and Wildlife Service (USFWS) or NOAA's National Marine Fisheries Service for consultation concerning the Endangered Species Act of 1973;
- US Army Corps of Engineers permits pursuant to the River and Harbor Act of 1899 (33 USC. 403) and Section 404 of the Clean Water Act (33 USC. 1344).

The Environmental Impact Statement (EIS) is a coordinated document that is used by all cognizant agencies for the processing of their corresponding permits, certificates and licenses. The joint EIS satisfies the requirements of the governing laws: mainly the National Environmental Policy Act, the Deepwater Port Act, the Natural Gas Act, the Rivers and Harbors Act and the Clean Water Act. The EIS reflects the opinion of the contributing federal agencies.

As mentioned above, under the DWPA the States have certain rights and responsibilities which are similar but not equal to those available for onshore facilities. The governors of the "designated adjacent" coastal states have the right to veto projects. This power is not afforded to the governors for onshore facilities.

In addition to the final veto (or not), the States must determine the consistency of the offshore LNG facility with state coastal zone management plans made under the Coastal Zone Management Act; issue leases for any use of state submerged lands for natural gas pipeline purposes; approve any new intrastate natural gas pipelines that must be developed; and be involved through their State environmental agencies in the Endangered Species Act consultation process. Finally, certain local land use approvals must be obtained by offshore LNG project developers for any associated onshore facilities.

The process for licensing deepwater ports only has been pursued a limited number of times. Because of this, and the impossibility of having a fixed set of explicit requirements for applications, the regulatory hurdle is evolving. Each new project usually has to meet all previous hurdles and any new hurdles determined by the specific circumstances of the project (e.g. graving docks for gravity based structures, open rack vaporizers for regasification of LNG; see later sections for descriptions and definitions). This will lead to evolving and ever tightening requirements for the issuance of licenses for offshore LNG terminals and to the eventual revisiting and clarification of the license application and issuance procedure[23].

In addition to the license for the deepwater port, applicants still have other permits to seek post-licensing approval of detailed engineering plans, and operations and security manuals.

The path towards the decision for granting a license is clear and bounded. However, the same does not necessarily apply for the granting of any additional permits that are required. For example, the timelines for the granting of some of the additional (required) permits from other agencies do not have strict milestones and procedures. That uncertainty could result in unforeseen delays and additional regulatory risks therefore adding risks and costs to projects.

The intent of an EIS is to identify adverse environmental impacts that could occur as a consequence of the project being proposed. The environmental impacts considered range from construction and operation to eventual decommissioning. When impacts are identified, depending upon their magnitude, specific plans and procedures are developed or required to be

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[23] An example is the codification into the EPACT of 2005 of the FERC Hackberry LNG decision which put onshore LNG terminals on the same level as offshore LNG terminals not requiring them to provide open access to terminal capacity as is required in natural gas onshore pipelines.

developed and approved in order to mitigate such impacts. The actions identified are usually conditions for the granting of the DWPA license and associated FERC certificate (for associated onshore pipelines).

The discussion of the mitigating actions and their acceptance both from the perspective of the commercial developer of the site and the other interested stakeholders is another case in which uncertainty reigns. For example, even though an EIS may evaluate a technology and accept the mitigating measures adopted, governors of adjacent coastal states and their staffs may not reach the same conclusions and recommendations and veto the proposed license. In lieu of a veto, the license can incorporate additional conditions at the request of the States such as “environmental monitoring and mitigation measures and reporting requirements”. In addition, States may charge “reasonable fees for the use of the deepwater port facility to offset any economic, environmental, and administrative costs”[24].

Overview of Offshore LNG Receiving Terminals and Modes of Operation

LNG import receiving terminals serve the purpose of providing the necessary infrastructure that link LNG tankers with natural gas pipelines. LNG import receiving terminals are part of the full supply or “value” chain that facilitates delivery of natural gas from fields in remote locations.[25] Many different processes and procedures can take place at an LNG import terminal (either on the LNG tanker or at the terminal facility itself) before natural gas can be delivered to market: docking of the LNG tanker, offloading from the LNG tanker (in the form of LNG or vaporized LNG), possible storage of LNG, vaporization of LNG, possible storage of natural gas, and interconnection to natural gas pipelines to name the most relevant. There are different

[24] Document USCG-2004-17696-228

[25] See “LNG Safety and Security”, the second briefing paper in CEE-UT’s online Guide to LNG in North America for a detailed review of LNG value chain operations, www.beg.utexas.edu/energyecon/lng.

approaches to designing and operating LNG receiving terminals depending upon the markets they serve and the infrastructure requirements they have. This is particularly true with respect to offshore LNG import facilities.

One useful way of grouping offshore LNG terminals is based on their associated storage facilities[26] since that affects the possible designs and modes of operation. If the offshore LNG terminal has sufficient storage capacity, the terminal can supply natural gas for base load operations (meaning natural gas supplies that must always be delivered on a daily basis) in a continuous and constant manner. The terminal can also provide supplies that meet some peak demand events. The capacity of a typical tanker arriving at the terminal divided by the send-out capacity of the terminal should yield a result that matches the average time between tankers in order to be able to continuously provide natural gas output.

> *Capacity of typical tanker ÷ sendout capacity of terminal = average time between tanker deliveries for continuous natural gas output*

On the other hand, the minimum amount of terminal storage capacity required for continuous operations is equal to the volume of the average LNG tanker delivery. Since all aspects of the natural gas/LNG value chain cannot be expected to function like clockwork, additional volumes of terminal storage are required in order to compensate for delays in shipments and to limit demurrage (detention or delay of a tanker due to loading or unloading), to name two factors. Most terminals are designed to have between two and three tanker volumes of storage in order to be able to manage variations in supply or demand. That implies associated storage anywhere between 125,000 m^3 to 300,000 m^3 of LNG or its equivalent in natural gas.

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[26] LNG import terminals can have associated LNG storage capabilities, natural gas storage capabilities (e.g. salt domes) or both. If the terminals have storage capacity that is exclusively used for the operation of the terminal and the eventual delivery of the natural gas to market, the related infrastructure would not be subject to the same open access requirements that exist for commercial natural gas storage.

Terminals that do not have associated storage (be it in the form of LNG or in the form of natural gas), or that do not have enough storage, must deliver the natural gas to the pipeline system at the same rate that ships offload or nearly that rate. From the perspective of natural gas pipeline operations, the flow of natural gas fluctuates and may even be intermittent in between the offloading of LNG tankers. There is a clear trade-off between the costs associated with storage and the costs due to increased capacity requirements in the takeaway pipelines. In most cases, since the timing of LNG shipments with peak supply events is nearly impossible, the intermittent supply of natural gas for this sort of facility (or the resulting displaced gas) will likely find storage facilities within the natural gas network in order to smooth supply over time.

Main Elements of an Offshore LNG Receiving Terminal

LNG receiving terminals have a variety of process elements that must be placed on a structure (floating or fixed). In the following sections the most important process and infrastructure elements will be presented and the different technological approaches for each will be described.

- Main Structure: Fixed (gravity based structures, offshore platforms) and floating(floating storage and regasification units).
- Regasification/vaporization of LNG
- Associated storage facilities (for LNG or for natural gas)

Main Structure of Offshore LNG Terminals

Water depth of proposed locations is usually the variable that determines the type of main structure to consider. When considering siting of LNG offshore terminals, a wide range of possible locations present themselves. LNG vessels typically have a draft of 38 feet and require at least an additional two to 5 feet of depth to provide sufficient clearance from the sea bottom for safe maneuvering. This means that the minimum water depth for siting LNG offshore terminals will be determined by the minimum depth of water required for the safe maneuvering of the LNG vessels, which is about 40 to

43 feet or approximately 14 meters. At present, there is no maximum depth of water that would limit the location of an offshore LNG terminal, but ultimate water depths for safe, economic operation are also determined by geometry of the sea floor, wave action, distance from shore, and other factors.

In addition to water depth, the distance to the shoreline has become an important factor, not only for the basic economic considerations of increased depth (in most cases) and increased pipeline length, but from that of visibility, that is visibility from the coastline. The issue of visibility from coastlines has become important in coastal areas that are not accustomed to offshore structures. In such cases, LNG project proponents take great strides to develop aesthetically acceptable solutions and to determine the real visual impact of such structures (see Figure 4 for a simulation of visual impact of a proposed offshore LNG facility). The tradeoff between closer locations to the shore and greater visibility and locations further away and less visible is a tradeoff between increased costs due to greater depths and longer pipelines for delivery to markets[27].

Figure 4 View[28] of Proposed Cabrillo Port FSRU Location from Point Dume under Clear Sky Conditions

[27]Said, Mike and Joram Meijerink, Shell Global Solutions International B.V., *LNG Import Terminals: "Offshore vs Onshore" - A Site & Concept Screening Methodology*, 14th International Conference on Liquefied Natural Gas (LNG-14), Doha, Qatar. March, 2004.

[28] Source: Revised Draft EIR for Cabrillo Port, March 2006.

As noted earlier, some of the advantages of offshore LNG terminals include the possibility of locating the terminal in deeper water thereby eliminating the need for dredging inland waterways and increased availability, safety and reduced voyage time as LNG carriers need not enter and maneuver in congested waters.

In the US, the DWPA of 1974, as amended, specifies the regulations concerning offshore oil and gas terminals. As mentioned before, the DWPA established a licensing process for ownership, construction and operation of manmade structures beyond the US territorial waters. The limit of the US Exclusive Economic Zone (EEZ) sets the maximum limit for siting LNG offshore terminals. In concept, this would include any location along the maritime coastline of the US in the Atlantic Ocean, Pacific Ocean, or Gulf of Mexico (GOM) in the US EEZ, and that is outside state waters, which is most cases is at least 3 miles offshore. Since the DWPA was passed it has been modified twice to streamline the application process and to promote the offshore importation of natural gas in addition to oil. The last modification, described earlier, was in November 2002 when the Maritime Transportation Security Act of 2002 (MTSA) was signed, which formally amended the DWPA to extend the definition of deepwater ports to include natural gas facilities and implement measures to improve vessel and facility security. Ports must not be sited in areas specially designated as vessel navigation routes, cargo operations areas, or environmental protection and conservation areas.

Generally, the USCG has established a 500m safety zone surrounding the offshore LNG terminal to exclude ship traffic not related to the port operations, although this can be terminal and site specific. The requirement of this safety zone necessitates that the offshore LNG terminal be located away from shipping fairways, existing oil or gas platforms, other deepwater ports, and other areas of activity on the Outer Continental Shelf (OCS) to avoid interference with those activities. Other considerations of location, such as proximity to existing offshore and onshore pipeline distribution systems and support infrastructure, will also influence the cost effectiveness of a deepwater port

A significant number of the proposed LNG offshore terminals are in the US GOM. The GOM provides many favorable conditions for the development of offshore LNG terminals. Extensive existing onshore support infrastructure and the general economy of the Gulf area strongly support development of offshore LNG terminals. In addition to onshore resources, the GOM offers access to an extensive existing offshore pipeline infrastructure with direct access to major onshore distribution points.

As is usually the case there are many ways to group the types of structures that could be used for offshore LNG facilities. We consider a simple classification: fixed or floating.

Fixed Structures

Three types of fixed structures are presented here--gravity based structures (GBS), offshore platforms and artificial offshore islands. To date none has been used for LNG service in the US though most of the components have been used successfully in other applications. Fixed facilities are typically considered for shallow water offshore locations, with water depths typically limited to at most 100ft due to limitations at their construction sites. The fixed structures must also be located in areas where the seafloor is relatively level or gently sloping, lacking in geologic hazards, and with satisfactory sediments to support the foundation and weight of the structure. If there is a significant thickness of soft clays, the most effective means of founding the structure is by constructing concrete skirts. A concrete skirt is a vertical structure that cuts through the soft clays to harder material below.

The fixed structure allows for the consideration of terminal based LNG storage. However, given the size limitations of offshore platforms, most proposed terminals with storage are based on gravity based structures. Terminals based on offshore platforms mostly use existing platforms that will be adapted to LNG service and usually have cavern based natural gas storage associated with the facility or pipelines with sufficient takeaway capacity.

The process elements associated with offshore LNG are very similar in the fixed structure terminals and are briefly described below.

Gravity Based Structures

Gravity Based Structures have been used to support offshore crude oil facilities for more than 30 years. The construction is mostly concrete and in the case of LNG is adapted to handle contact with cryogenic liquids.

Figure 5 Shell Gulf Landing

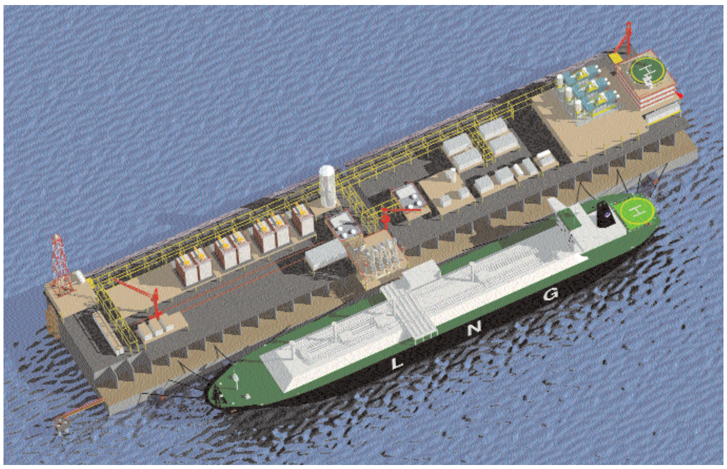


Figure 6 ExxonMobil Isola di Porto Levante (First GBS LNG Terminal under construction)

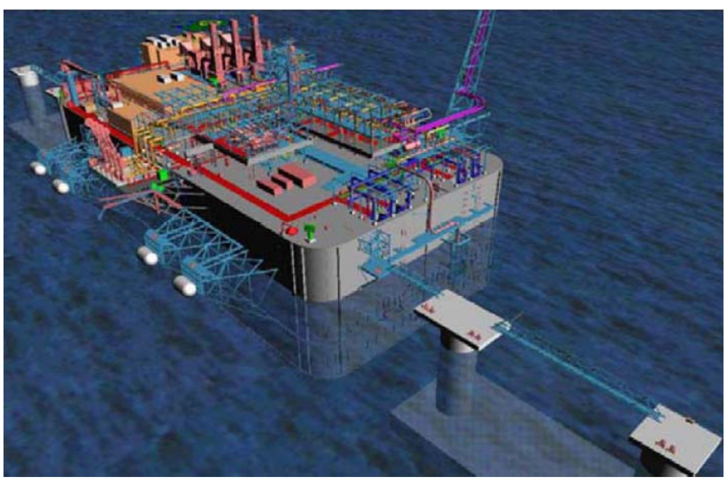
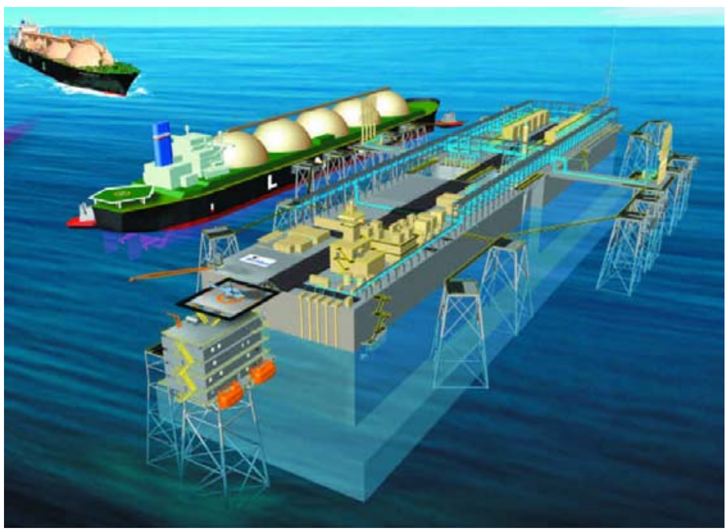


Figure 7 ConocoPhillips Beacon Port

Figure 8 Chevron Port Pelican



The GBS concept is well suited to phased expansion. Additional GBS units may be constructed and installed adjacent to existing facilities and linked to the existing GBS by a shallow water jackets and a bridge. Significant synergies can arise due to the sharing of production utilities, storage and offloading facilities for the phased expansion of the facility. The size of the GBS is defined by the storage volume or topside area required for the support of facilities or a combination of both requirements.

GBS Components and Configuration

Guidelines and special requirements for the use of GBS structures in LNG service have been developed[29] that consider the cryogenic temperatures that are encountered and the resulting stress on the structure. The LNG terminal usually consists of several reinforced concrete GBSs. The GBSs support the control and maintenance buildings and utilities, regasification facilities, and LNG storage tanks to name the most important components. High-strength cement technology and steel reinforcing would be used to design the GBSs to safely withstand extreme stresses like the force of the Loop Current that is a permanent feature of the US GOM, severe wave loads caused by hurricanes or major storms, and other stress-inducing events including vessel impact.[30] If the GBS is sitting in about 60 to 80 ft of water, there will be about 70 to 90 ft of freeboard above the seawater level.

GBS Fabrication

GBS fabrication and installation of the majority of the LNG tanks and regasification equipment would be performed at a shore-based facility. The GBS needs to be constructed inside an unflooded dry-dock and the operating equipment installed and tested. The dock would then be flooded in order to float the GBS to the installation site. The GBS would then be towed to the terminal site and fixed to the seabed. The installation procedures generally involve gradually lowering each GBS to the seafloor using ballast tanks around the perimeter of the GBS. The skirts on the bottom of the GBS would require jetting away the softer sediments so that the GBS skirts can be drawn into the seafloor to firmly anchor the GBS at the site. Once the GBS is in place, the remaining operating equipment would be installed and connections made between the GBS quarters platform and offloading platforms. Lift barges would be used to install some aspects of the terminal.

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[29] "Guidelines for Building and Classing Offshore LNG Terminals", December 2003, American Bureau of Shipping.

[30] US Coast Guard: Maritime Administration: Final Environmental Impact Statement for the Port Pelican Llc Deepwater Port License Application. August 2003.

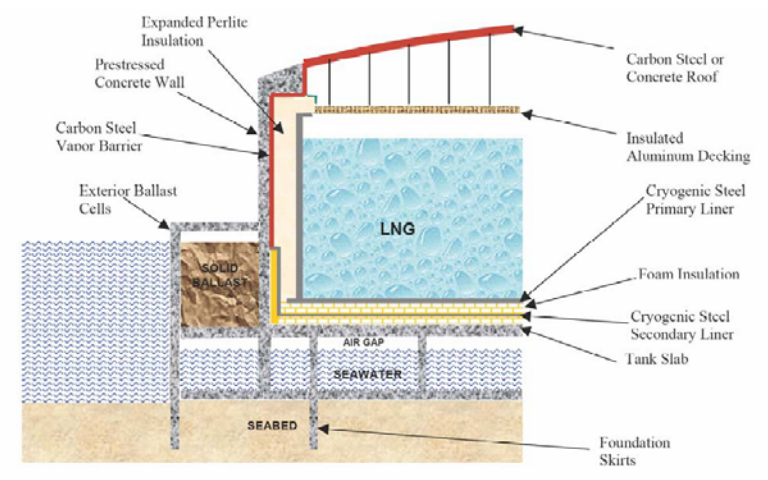
The pipeline would also have been fabricated and installed. The LNG terminal would then be placed in service after a series of final testing and inspections.

GBS fabrication presents a unique opportunity for the incorporation of local content into LNG terminal projects. However, this is also an area of attention for EIS review due to the associated dredging and coastal impacts

LNG Storage on the GBS

The LNG is stored within the GBS hull in a double containment tank with membrane liner. The GBS would have integrated LNG tanks. The substructure is made up of concrete walls and slabs for ease of construction. Concrete is particularly well suited to the storage of cryogenic liquids like LNG. Submerged LNG cargo pumps are placed inside the tanks to transfer LNG from storage tanks to LNG sendout pumps mounted on the GBS deck[31].

Figure 9 Offshore LNG Storage tank Cross Section[32]



LNG storage tanks are fitted with thermal insulation to prevent heat transfer into the cargo tank, to reduce boil-off of the LNG, and also to protect the structure from cryogenic temperatures that would cause brittle fracture. The insulation is either "sandwiched" between the inner hull and primary

[31] Raine, B., Kaplan, A.; *Concrete-based offshore LNG production in Nigeria*, LNG journal September/October 2003.

[32] Docket for Beacon Port Application for Deepwater License

membrane, or in the case of Moss tanks[33] applied externally. The insulation is protected from external sources of ignition by the steelwork of the tank's structure[34]. However, some LNG is vaporized in the tank by heat picked up from the surroundings. This vapor is referred to as boil-off gas (BOG). The vaporization, at atmospheric pressure, of natural gas from the LNG is a process that occurs at constant temperature, which is the temperature of the LNG. This process is comparable to water boiling in an open pan, except the temperature is much lower[35].

Platform Based LNG Import Terminals

Much like Gravity Based Structures, offshore platform based LNG terminals are non-floating and allow for the consideration of terminal based LNG storage[36]. The proposals seek to use existing infrastructure (offshore platforms) to develop the LNG terminals. Given that most of the platforms were originally developed for hydrocarbon production or mining operations, the availability of above water "real estate" is limited.

The main facilities are located on the topside of the offshore platforms. In the case that there is no terminal based LNG storage, LNG would be delivered by ships and vaporized to natural gas on the platform and immediately delivered to the sendout pipelines. In order to provide continuous supply capabilities to offshore based terminals, most incorporate significant storage capacity for the vaporized natural gas in the form of salt caverns such as the case of the proposed Freeport-McMoRan Main Pass Energy Hub terminal. As mentioned above in the section on operating modes, in the case that there is no storage

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[33] See CEE-UT ***LNG Safety and Security*** for details on Moss and membrane LNG storage tank designs, www.beg.utexas.edu/energyecon/lng.

[34] See UT CEE LNG FAQ '*Understanding LNG Cargo Tank Insulation*" www.beg.utexas.edu/energyecon/lng

[35] Regardless of the amount of heat transferred from a stove burner to a pan of boiling water, as long as the pan is open to the atmosphere to allow steam to disperse, the temperature of boiling water will remain at approximately 212º F (100ºC). If the pan were covered and sealed, the steam pressure would build and then the temperature of the water would increase. Boiling water at atmospheric pressure will remain at 212º F while steam boils off, similarly LNG at atmospheric pressure will remain at approximately -260º F while natural gas boils off.

[36] Though only limited volumes of LNG.

capacity on the platform for the LNG or vaporized natural gas, the gas grid has to be able to absorb large amounts of gas in a short period, in addition to the market allowing for an interrupted supply of gas. In addition, depending on the throughput of the pipeline, the time that tankers will need to remain in berth could be longer.

Figure 10 Freeport-McMoRan Energy Main Pass Energy Hub

Figure 11 Clearwater Port Terminal

Artificial Offshore Island Based LNG Import Terminals

One novel approach used for many other types of facilities is that of the construction of an offshore artificial island. This alternative provides the greatest "real estate" of the fixed structure alternatives. It provides space for LNG storage, multiple docking berths, air based vaporization and other space extensive services and processes. To date only one project based on an offshore island has been announced for the US[37]. The concept allows for the use of onshore LNG tank designs, and other onshore technologies since space considerations are not as important as in the platform based terminals.

Figure 12 Example of offshore artificial island south of Saltholm, part of the Øresund Fixed Link, May 1997.[38]

Offloading LNG Ships

The berthing and unloading facilities for LNG ships would include one or two LNG ship berths and a berthing control tower to manage all berthing operations and procedures. The mooring system would allow one or two LNG ships to be moored alongside the structure. LNG ships would berth anytime of the day or night, subject to suitable weather conditions. The LNG offloading facilities would be designed to accommodate LNG ships ranging in capacity from 100,000 m^3 to 160,000 m^3 or more depending on the water depth at location[39].

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37 Atlantic Sea Island Group's Safe Harbor Energy Project

38 Source: http://www.oeresundsbron.com.

39 Both onshore and offshore terminals are considering Q-max and Q-flex vessels up to 265,000 m3.

Figure 13 Marine Loading Arms for LNG Service[40]

Ship cargo transfer would use a loading arm package per berth. The loading arm package normally consists of four 16-in diameter loading arms. The loading arms would be similar to those used at existing onshore LNG facilities; however, the specific configuration would be designed to accommodate offshore ship movements at berth. LNG ships would offload through three of the four loading arms. Typical offloading rates would be about 10,000 - 12,000 cubic meters per hour (m^3/hr) (353,000 to 423,600 cubic feet per hour (ft^3/hr) of LNG. The fourth loading arm would be dedicated to vapor return from the terminal to equalize pressure between LNG ship and terminal storage tanks. One of the three arms used for liquid could be used for vapor if the vapor arm is damaged, but offloading rates would be reduced. During the absence of LNG ships at either berth, LNG from the storage tanks can be circulated in the terminal offloading piping network to maintain cold temperatures for the next ship cycle, minimizing the need for cooling down the pipes when the next ship arrived. The time LNG ships

[40] Source: FMC Technologies Chiksan®

would spend at berth would be approximately 24 hours (hr), including berthing, hookup, offloading, disconnect, and un-berthing[41].

LNG Sendout Vaporization

LNG vaporization would take place in a similar fashion to onshore. The LNG sendout pumps discharges LNG into the LNG vaporizers where it would be warmed. The terminal may have more than one parallel vaporization train to warm up and convert the LNG to natural gas and deliver the gas to the pipeline at the required pipeline pressure of about 1450psi. Each vaporization facility would consist of smaller trains, each with an LNG sendout pump, a vaporizer, and a heating fluid handling system (seawater lift pump, air handling unit, or natural gas, depending on the source of heat).

Gas Metering

Natural gas from vaporized LNG would pass through a custody transfer meter system before entering the pipeline. Metering capacity for the pipeline would match the peak discharge capacity from the LNG sendout pumps.

Utility Services

All services not in direct contact with the delivered LNG are considered utility rather than process services. Utility services include power generation, instrument and utility air, open drains and oily water treatment, fuel gas, utility water, the hypochlorite system, potable water, wash down, nitrogen generation and high pressure storage, wastewater treatment, diesel fuel, aviation fuel, the emergency flare system, and fire and safety systems.

The electrical power for the terminal can be generated by natural-gas-powered turbine generators. Gas would be supplied by the fuel gas system from boil-off gas with emergency diesel generators. The emergency diesel

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[41] The time at port is highly dependant on the facilities ability to accept LNG (or natural gas). If the facility has LNG storage available, the time at port is reduced. If on the other hand, there is not LNG storage, the LNG must be vaporized and sent to natural gas storage facilities (which have there own maximum rates) and/or natural gas pipelines (which have there own maximum takeaway capacity).

generators would allow operation during the absence of natural gas or during emergency situations involving the turbine generators. The facility would receive bulk diesel from supply vessels.

Emergency Flare System

To meet applicable safety standards, an emergency gas flare would be installed on a separate support structure adjacent to the end of the process areas. The flare would be oriented such that the prevailing winds would direct its plume away from the main facilities. If offshore, the flare would be accessed using an extended gangway. A flare header system would collect hydrocarbon flows from relief valves, tank blankets (air spaces around the tank with nitrogen and natural gas sensors), and miscellaneous sources and send them to a flare drum and then to the flare. The flare would be equipped with multiple pilots and electronic igniters.

Living Quarters and Helideck

Crew quarters would be placed on a free-standing platform a short distance from the utility area, farthest from the process areas and emergency flare in order to meet the requirements for safety setbacks from the LNG tanks. The building would accommodate about 50 personnel, offices, recreation, communications, and a galley.

Mooring System

Mooring of LNG ships at the terminal would be carried out through a combination of both breasting and mooring dolphins. Breasting and mooring dolphins are clusters of piles driven and bound together at the top (or a large diameter pile) used to moor, anchor, breast or turn a vessel and also to protect bridge piers and docks. Tugs would be required to assist in berthing and un-berthing the LNG ships.

Decommissioning

GBS terminals may be designed for up to 40 years of service. Once the end of the useful life of the facility is reached, decommissioning involves removing all underwater structures and leaving facilities in place below ground. The decommissioning procedure is a reverse of the installation procedure. This would be similar in the case of offshore oil and gas production platforms. The trend to use offshore structures for environmental projects such as marine preservation will likely affect the decommissioning procedures for offshore LNG GBS structures[42]. It may be desirable to leave the fixed structures of these facilities in place in order to enhance marine habitat and provide for commercial and recreational opportunities. Final determination regarding alternative uses would be made at the time of decommissioning, but the owner would have to provide bonding or other means of demonstrating the financial ability to provide for the estimated decommission costs at the end of the facility's useful life.

Floating LNG

As projects move further away offshore, water depths increase beyond those permissible for fixed structures and must consider floating facilities. In general, the same processes are considered for floating facilities: docking, offloading, storage, and regasification. Different processes can be part of the floating facility, for example, if storage and regasification are part of the facility, then they are commonly called a Floating Storage and Regasification Unit (FSRU). If storage is not incorporated into the floating facility, then a Floating Regasification Unit (FRU) is considered.

Floating Storage and Regasification Unit - FSRU

A FSRU LNG import terminal concept comprises of a purpose built moored[43] ship with several LNG ships shuttling between the export facility and the import site. The FSRU ship is typically between 350 to 400 meters long by up to 70 meters wide and normally does not have a complete propulsion system. There are applications in which rapid disconnection and relocation of

[42] "The Ecological Role of Oil and Gas Production Platforms and Natural Outcrops on Fishes in Southern and Central California: A Synthesis of Information" by Milton S. Love, Donna M. Schroeder and Mary M. Nishimoto of the University of California at Santa Barbara

[43] FSRU's are mostly permanently moored but may have to disconnect on occasion.

the FSRU is a requirement. In these cases, a propulsion system will be part of the FSRU. Floating structures with storage capacity generally require an anchoring system and sufficient water depth (generally greater than 160 ft) to accommodate a flexible pipeline connection between the unit and the seafloor pipeline.

FRSU Components and Configuration

The FSRU consists of a double-hulled ship designed using normal shipbuilding blueprints and standards and can be constructed in a wide range of conventional ship yards worldwide. The regasification facilities are located on the main deck of the ship and are typically tailored to suit the specified gas send-out conditions.

Since the FSRU is part ship, part storage tank, and part re-gasification unit, three separate design standards, guidance, and regulations must be satisfied. The vessel portion of the FSRU is subject to marine codes, the LNG storage tanks are subject to LNG storage and transfer rules, and the LNG re-gasification and send out processes are subject to process standards and codes. Utilities and systems associated with FSRU operations include electric power generation and distribution, instrumentation and controls, and fire and safety systems.

Figure 14 Underwater connections for FSRU[44]

[44] Source: Excelerate Energy

Figure 15 Proposed Cabrillo Port FSRU[45]

Figure 16 Rendering of LNG Tanker Offloading at Cabrillo Port FSRU[46]

LNG Carrier Offloading

LNG offloading is typically achieved using a modified version of conventional LNG loading arms similar to those used on the GBS LNG terminals. LNG ships will be berthed and unloaded on the starboard side of the FSRU which is the right side of the FSRU as you are facing forward. The starboard side will have four loading arms packages. LNG carriers typically will be offloaded and the LNG stored in the LNG storage tanks. During offloading operations, all the

[45] Source: "The Cabrillo Deepwater Port", BHP Billiton Brochure

[46] Source: Draft Environmental Impact Report: California State Lands Commission

cargo will be discharged except for retained heel required for tank cooling during the return voyage. The resulting change in draft as a result of offloading of cargo is typically very small.

LNG Storage

The LNG storage system is based on standard designs for ship cargo containment systems; using spherical tanks, membrane or prismatic freestanding tanks[47].

LNG Sendout Vaporization

The available vaporization options are discussed below and selection would be based on required send out capacity, space available, operating efficiency, safety, impact on the environment and cost.

Boil Off Gas

As discussed above in order to control the boil off rate the LNG tanks on the FSRU are insulated. The boiled off natural gas will be sent out through the natural gas send-out line, in come cases it can be re-liquefied or it may be collected and used as boiler fuel on the FSRU.

Fiscal Metering

The LNG storage tanks are fitted with precise instrumentation such as a radar type gauging system. This system is used for custody transfer application and is fitted with a separate monitor in the control room. For metering of send-out gas two ultrasonic in-line gas flow meters can be used. One unit will handle the peak gas flow with the other unit as a stand-by. Flow, temperature and pressure signals are usually transmitted to a flow computer with display and printer located in the control room, which can transmit to shore if desired. The system will be supplied with a certificate for fiscal accuracy and be periodically re-evaluated for accuracy.

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[47] See UT-CEE briefing paper, *LNG Safety and Security*. www.beg.utexas.edu/energyecon/lng. October 2003

Utility Services

Similar to the GBS, the power generation for the ship services are normally provided by gas turbines with dual fuel diesel engines as back up (sized according to the requirements of the regasification equipment).

Living Quarters and Helideck

The crew quarters are generally located at the stern so as to provide the maximum distance between the turret and accommodation unit. An accommodation deck house with all facilities for a permanent crew of up to 30 persons with temporary accommodations for another 20 persons in fold-down bunks, and a helideck will be fitted at the aft end in a non-gas dangerous zone. One free-fall lifeboat and two large life rafts complete with escape chutes will are fitted at the stern of the terminal for evacuation during an emergency. The supply vessel from shore for provisions and crew changes also will be berthing/de-berthing at the aft section of the terminal. A multipurpose control room will be installed in the accommodations to control and monitor all aspects of the terminal's operations, and will utilize remote monitoring of the normally unmanned process area and utility equipment.

Mooring System

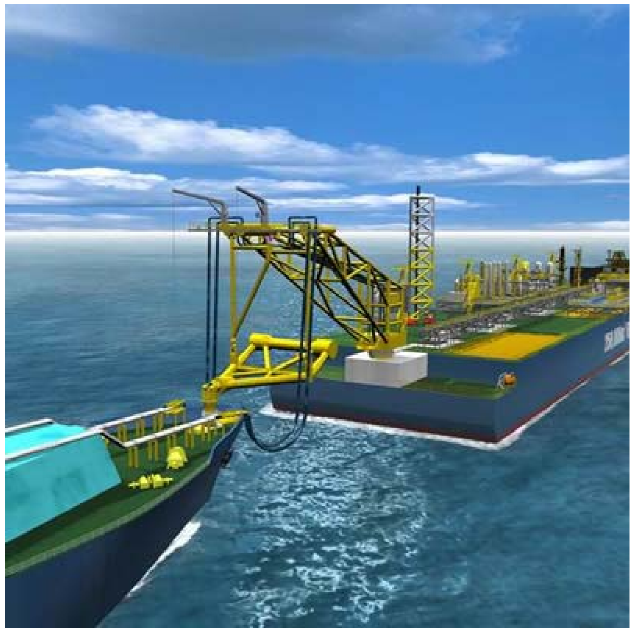
The vessel is a turret moored floating receiving unit designed for loading LNG from a side-by-side moored LNG tanker in a relatively benign range of environmental conditions. The LNG carrier is moored alongside the FSRU with both vessels weathervaning around the FSRU's turret mooring.

Figure 17 LNG Tanker side-by-side to FSRU Loading Arm Schematic[48]

In the event the FSRU is required to be located in harsher metocean conditions then the 'Stern to Bow' or 'Tandem' configuration can be used. While this tandem technology is still considered developmental several leading industry equipment suppliers are actively advancing it. A key advantage of the FSRU concept is that it can be moored in a wide range of water depths. In shallow waters (approximately 65 to 100 feet), a jacket based, soft yoke system can be used, in greater water depths a catenary based, turret mooring system can be employed. Both of these systems are weathervaning, allowing the FSRU ship's heading to rotate according to the direction and force of the wind.

[48] Single Buoy Moorings, INC.

Figure 18 LNG Tanker tandem to FSRU Loading Arm Schematic[48]



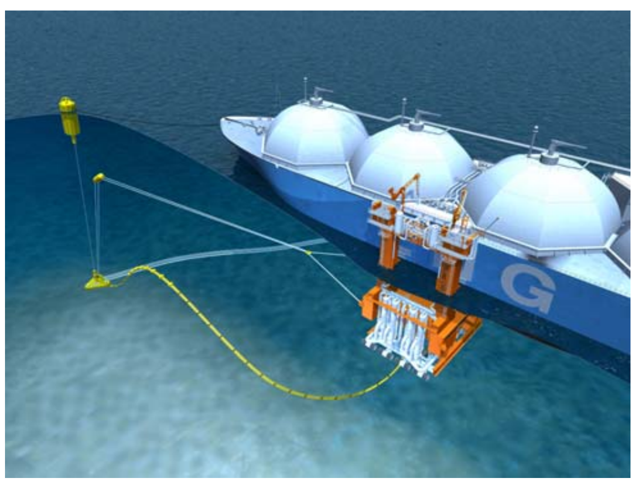
Other Floating LNG Configurations

An interesting case is that of the Excelerate Shipping Fleet which combines the capabilities of a conventional LNG tanker with that of an FSRU. Effectively, the Excelerate ships act as FSRUs when offloading natural gas directly into natural gas pipelines since it used the ship's facilities are used for storage and regasification. However, one important process is still lacking, the ship to ship transfer of LNG which in the case of the Excelerate ships is avoided since the LNG tanker and the LNG FSRU are in this case the same ship.

Figure 19 Example of a highly mobile FSRU: Excelerate Ships[49]

Another interesting example of a floating LNG facility is one that lacks local LNG storage (other than that of the LNG tanker) and allows for conventional LNG ships to dock[50]. In this case, conventional offloading arms are mounted on a purpose built floating structure (pontoon, keel and towers) which temporarily attaches to docking LNG tankers. Regasification is also performed on the floating structure with conventional regasification technology.

Figure 20 Floating Regasification without storage: TORP LNG[50]



[49] Source: Excelerate Energy NorthEast Gateway website

[50] The recently announced project for the Bienville Offshore Energy Terminal in Alabama is an example: http://www.torplng.com

Regasification / Vaporization of LNG at Offshore Facilities

One of the main processes of the delivery of LNG to markets is the regasification of the LNG. The LNG, which is stored at atmospheric pressure, is pumped to the vaporization units were heat needs to be added to the LNG so that it changes phase to a gas and it can be put in pipelines in non-cryogenic conditions. The thermal load required to vaporize LNG is considerable: for example, to generate 1 BCF/d of natural gas it is requires 850 MMBTU/h. This is equivalent to 1.3 percent to 2.5 percent of the heat content of the LNG being vaporized. There are several different primary sources of heat that can be used to vaporize the LNG. Given its very low temperature they range from burning part of the natural gas itself to heat exchange with ambient air or seawater. Safety during operations, commercial viability, operability and maintainability, space requirements and suitability for offshore use and environmental impacts are some of the parameters considered in selecting the appropriate vaporizers.

Heat exchangers with seawater as the primary heat source

The exchange of heat with seawater in order to vaporize LNG is the most widely used technology in the world (although not so in the US). There are two main designs that use water as the primary source of heat: open rack vaporizers (ORVs) and shell and tube vaporizers (STV). In order to modularize the process and avoid freezing of the seawater, intermediate fluids (e.g. propane) can perform the direct heat exchange at low temperatures. The intermediate fluid would then exchange heat with the seawater.

The most common technology used for LNG vaporization is Open Rack Vaporizers. The operating principle behind the ORVs is the heat exchange between the LNG located inside heat-conducting, zinc alloyed, finned panels and a falling film of seawater at atmospheric conditions flowing over it. The panels need to be cleaned periodically to remove any foreign matter that might have adhered to the panel surfaces.

Figure 21 Open Rack Vaporizer

Shell and tube heat exchangers can also use seawater but in this case the heat exchange takes place with the LNG inside tubes and seawater flowing around the tubes inside a shell. This is also a proven technology with slightly higher process intensity due to the controlled fluid flow fields in the shell tube configuration. However, due to the probability of a tube rupture, there is the added reliance on a safety valve in the shell in order to avoid increased pressures and explosion risks.

In some applications, instead of only using seawater, other fluids are used for the low temperature heat transfer such as glycol-water solutions. This increases the ability of the unit to operate at low loads or turndown, by postponing the limit in which the fluid used for heat exchange freezes.

Figure 22 Shell and Tube LNG Vaporizer

System design and the effects on Water Quality and Marine Life

ORV and shell and tube designs have been proven safe, have no moving parts and lack ignition sources. Similar heat exchangers are extensively used as heat sinks in power plants. In both cases, significant volumes of seawater are required to provide heat and thus large electrical loads are required for pumping the seawater[51]. In addition to the restrictions on the seawater discharge quality (intake-suspended materials and discharge-temperature[52]), there are possible environmental impacts from the use of biocide for the prevention of bio-fouling and the intake of sea fauna because of the large flow rates of water. The possible environmental impacts determine the dosage and schedule of biocide usage (usually chlorine based).

The possibility of the intake of sea fauna is addressed through specific design considerations such as positioning of the low velocity intake at depths where the impact is minimized. First, the inlet velocity is reduced by increasing the diameter of the intake. The lower velocities allow larger marine organisms the opportunity to swim from the intake and avoid impingement which could lead to injury. On the other hand, larger volumes (higher fluid speeds for a fixed inlet diameter) reduce the cooling of the seawater and thus reduce the impacts at discharge[53].

For the intake, the geometry, location, orientation and protection (via mesh screens) seeks to minimize entrainment of smaller marine organisms such as eggs, larvae and young juveniles that cannot propel themselves free from the intake. Different approaches must be considered depending upon the location of the application. Great concern has been raised as to the impacts of open loop seawater vaporizers on fisheries in the US GOM due to the entrainment of the fish larvae. The US Clean Water Act (CWA)[54] requires

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[51] Thus there is a need for primer movers for the pumps which is limited on offshore facilities.

[52] The difference in temperature is between 5 and 15 C.

[53] There is no clear guideline for the environmental limit of cooled water discharge. There is a guideline put forward by the World Bank Group for power generation facilities that covers heated water discharge that provides a limit of 3 C at a distance of 100m from the discharge.

[54] Environmental Protection Agency (EPA) Section 316(b) of the Clean Water Act www.epa.gov

that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact"[55]. In order to evaluate the best technology available, adequate models and data need to be available and the uncertainty that govern them needs to be determined and taken into account. The fishery entrainment protocol developed by the USCG uses SEAMAP data to estimate the number of eggs and larvae entrained by an LNG facility and to provide an estimate of the future number of age-1 fish that are impacted. The protocol can be divided into two parts, a static part that looks at data to predict entrainment and one that based on the first results, predicts fish lost to the coastal ecosystem.

Unfortunately, the availability of SEAMAP data near proposed LNG facilities, its variability in time and space, and specificity to different fish species is limited. This uncertainty in the data used for the analysis translates into uncertainty into the predictions made with the models (which themselves are approximations). The impact of the different approximations and incomplete data on these predictions can be estimated but given the additional approximations that need to be made (such as the lack of dynamic interaction of the entrained eggs and larvae with the future development of the surviving ones), uncertainty surrounding the predictions needs to be increased. The accepted practice is to look at estimated future impacts of the entrained larvae and eggs on the equivalent age-1 fish and to compare that number with fishery harvests. Figure 23 presents a sample analysis performed by NOAA in which the total number of eggs produced in the future is predicted, in the cases of no offshore LNG facilities using seawater and with the vaporizers.

The scientific literature reflects more data (though still lacking) for predicting into the future, than for looking into the number of egg-equivalents that are lost. The lack of data for what is called "hindcasting" adds additional

[55] The EPA is currently engaged in rulemaking for the discharge of cooling water used in condensers in power plants. In this case, the water that is discharged is hotter than ambient.

uncertainty to these predictions. Of interest is to run all models to see if there are consistent and if they agree within the levels of uncertainty. To date, a comprehensive analysis of the uncertainty in data and the uncertainty and approximations made in the models, and how all they interact has not been performed. In addition, the interaction of such analysis with the proposed monitoring processes has not been performed.

Figure 23 NOAA[56] Red Drum Cumulative Impacts to Recovery Curve

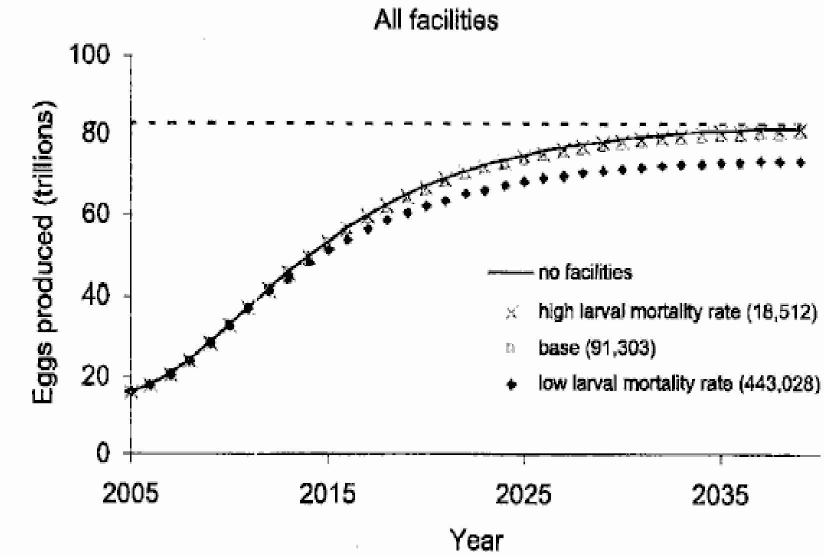

Figure 1. Projections of aggregate spawning stock fecundity (total eggs produced) of Gulf of Mexico red drum when the fishing mortality rate is set equal to the value that will eventually achieve a spawning potential ratio of 30% (F30%=0.47). The solid line represents the projection results when the LNG facilities are not considered. The dashed horizontal line represents the equilibrium value associated with a 30% spawning potential ratio. Symbols represent the projection results when LNG age-1 equivalent kills are subtracted from the population beginning in 2009 (the numbers in parenthesis give the estimated number of age-1 equivalents lost to entrainment for each scenario). The projections are based on the results of the 1999 assessment (Porch 2000) and assume that the present condition of the stock has not changed.

Since there is a lack of precise predictive data, in some cases, in order to reduce the inlet velocities and reduce the probability of entrainment, multiple inlets will need to be considered at different water depths. Warmer water, which is better for the vaporization process, is usually found closer to the surface. However, so is some of the marine life that needs to be avoided.

[56] Source: NOAA Fisheries SFSC 11 Jan 05 “Summary of Gulf Landing Entrainment Mortality Analysis”

Additionally, if the intakes are placed too close to the seabed, sediments can also be entrained. All these tradeoffs need to be taken into account for the design, operation and monitoring of the proposed seawater based vaporization processes.

In review, given the complexity of the systems under consideration, precise models and predictions cannot be made. However, an adequate system design that incorporates sufficient operational flexibility, tied to an environmental monitoring plan[57] that measures the impacts on the key marine fisheries and the related variables should allow for the timely adaptation of the operating scheme if undesired effects are eventually observed. Concerted efforts to evaluate impacts by state and federal agencies in cooperation with industry can lead to the development of the appropriate implementation of the technology, the formulation of adequate monitoring protocols and acceptance of seawater based technologies where deemed appropriate. In addition, concerted efforts to prevent further deterioration and to replenish and expand nearshore and wetlands environments, essential to the reproductive cycles of sports and commercial fish populations, are likely to yield substantial offsetting benefits. As well, the introduction of new marine habitat, in the case of fixed offshore LNG facilities, rapidly increases available supporting nutrients and productive areas for marine species. Numerous studies and long experience demonstrate the productivity associated with offshore oil and gas structures; this is the main impetus for preferences to leave offshore structures in place wherever possible.

The amount of seawater that would be used in offshore LNG vaporization processes is minute when compared to the total aquatic habitat of the Gulf of Mexico for example. The environmental impact of offshore LNG facilities should be considered within the context of the overall marine ecosystem and appropriate assessment and mitigation measures identified and deployed.

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[57] Likely to be developed in consultation with NOAA fisheries.

The environmental impact statements developed by the United States Coast Guard for proposed offshore LNG developments conclude that the general environmental impact would be minor and fall within acceptable limits. In addition, the estimated impact on fisheries would be minor. However, groups of stakeholders have raised concerns about the interpretation of the studies regarding the cumulative impacts if several offshore LNG terminals are built in the same region that would use seawater as the heating fluid.

According to findings from an independent ecological review of the environmental impact statements commissioned by The Center for Liquefied Natural Gas (CLNG), the actual impact of offshore liquefied natural gas (LNG) projects on marine life in the Gulf of Mexico will be substantially less than originally identified by environmental analyses. The CLNG commissioned Exponent, Inc., to undertake an independent evaluation of the technical work that has been done in assessing environmental impacts from use of seawater in ORV systems proposed in LNG terminals in the Gulf of Mexico[58].

Heat exchangers with air as the primary heat source

Another economically attractive approach is the use of air as the primary source of heat for LNG regasification. In this type of arrangement, ambient air is used to exchange heat with LNG. In the process the air is cooled and released to the atmosphere. In high humidity areas, considerable amounts of fresh water will be generated that can be used at the offshore LNG site. Additionally, due to the discharge of cool air, there is the potential to generate a fog bank if the appropriate weather conditions persist.

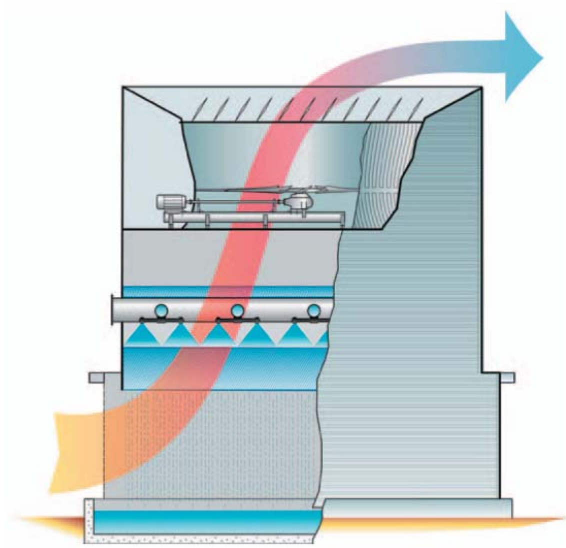
As is the case of water based systems, intermediate fluids (such as glycol) can be incorporated in order to intensify the heat exchange at very low temperatures.

The main problem with air based heat sources is that the process is heavily dependant on ambient conditions. In order to guarantee continuity of

[58] The Exponent Inc. report is available at http://www.centerforlng.org

operations a boiler backup is required. This technology has a larger footprint than water based systems and also weighs slightly more. In addition, units in this particular service have not been widely used commercially at this scale although they are under construction for one such facility in the US[59]. Air vaporizers have been successfully used in the Petronet LNG Terminal at Dahej.

Figure 24 Heating Tower for LNG vaporization with vertical discharge (Source: SPX Cooling Technologies)



Heat exchangers with natural gas as the primary heat source

Submerged combustion vaporization (SCV) is the most commonly used technology in the US for LNG vaporization. The energy content required for vaporization is equivalent to at least 1.3 percent of the LNG being vaporized as the source of the heat[60]. This implies a higher operating cost due to the fuel usage when compared with water- and air- based systems. In addition, due to the combustion, in addition to reducing the availability of the product, emissions are produced that must be taken into account when considering Clean Air Act Regulations. From a safety point of view, the presence of an

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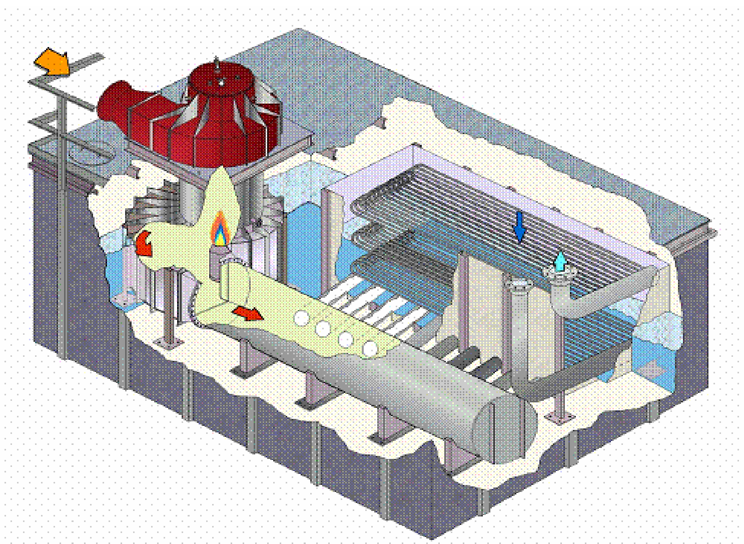
[59] Freeport LNG is planning to use air based systems in their onshore facility.

[60] Other sources of heat can be the low pressure boil-off gas and extracted heavier fuel gas from the LNG (e.g. ethane).

ignition source is a consideration. Finally, the use of SCVs in floating LNG facilities may run into problems due to sloshing of the fluids inside the chamber. This requires specially designed baffles in order to regulate the flows in the vaporizer. Unfortunately, the water bath tends to turn acidic due to the absorption of byproducts of the combustion. This acidity needs to be neutralized routinely in order to avoid corrosion. The neutralization process generates salts that will need to be removed before they can generate problems. One of the advantages is the high thermal capacity of the water bath which allows for stable operation during changes in load and during startup and shutdown procedures.

Figure 25 Submerged Combustion Vaporizer



Comparison of LNG Vaporization Technologies

Selection from among the different commercially available technologies for vaporization of LNG presents multidimensional tradeoffs between many factors. There is no universal optimum so they must be analyzed on an application by application basis. The main factors that need to be considered are: initial investment, operational costs, maintenance, reliability, availability, air emissions, water emissions, and environmental footprint and impact. Offshore applications differ from onshore applications in particular ways, most importantly with respect to the increased cost associated with the technology footprint.

As part of the environmental impact statement, all "available" technologies are considered for evaluation. The evaluation is commonly performed in two tiers and provides good guidance as to the merits of each technology from the many perspectives that are required. The Tier I evaluation criteria requires that the "technology pass the test of having been proven commercially viable by having been previously approved for use in a deepwater port application[61]". This restricts the introduction of novel technologies directly into offshore applications without extensive testing.

The Tier II Evaluation criteria touch upon the many tradeoffs and considerations mentioned above: proven technologies, equipment reliability, energy and electric power requirements, and efficiency of energy use, effects of water quality and marine life, impacts on air quality, safety, and costs.

Given that prior to Excelerate Energy's Gulf Gateway Energy Bridge Port no offshore facility was ever put into operation, the concept of "proven" must be based on onshore experience and extensive testing. After this particular consideration, the most important (scrutinized) factors are cost, air emissions, and the effects on water quality and marine life.

The final EISs for offshore LNG projects present a comparison of the best available technologies for vaporization of LNG. The economic comparisons performed use certain premises such as a fixed value of the LNG used to provide the vaporization heat and a fixed discount rate. The side-by-side comparison for a 1.6 Bcf/d sendout capacity is provided in Table 1. As was explained above, STV and ORV require less space than SCV. The capital expenditures are of the same order for the three designs. However, even at fixed and reduced LNG costs (only $3.00 per million BTU), the operating costs (mostly fuel related) are considerably greater for SCVs. The total cost over the lifetime of operation of the units is at least $800 million. The fuel usage also generates increased air emissions as can be seen in Table 2.

[61] Main Pass Energy Hub Deepwater Port License Application, Final Environmental Impact Statement, Page 2-11.

Increasing attention to greenhouse gas emissions compound the dilemmas associated with choice of SCV technology for LNG operations.

The operational cost for SCV contrasts strongly with the use of seawater for heating. ORVs use approximately 90,000 to 125,000 gpm at only the cost of treating and pumping the seawater (and the cost of any required monitoring plan). If there is sufficient seawater available and environmental impacts can be mitigated and managed at reasonable costs, seawater-based systems not only make economic sense but may prove to be more environmentally attractive overall than combustion based systems.

Table 1 Comparison of LNG Vaporizer Technologies[62]

	Vaporizer Technology				
	SCV Low NO_x Option 1b	SCV/SCR Option 1d	ORV Option 2a	ORV-WHR Option 2b	IFV Boiling/ Condensing Option 3b
Operating Parameters					
Proposed Peak Vaporization Capacity (bscfd)	1.6	1.6	1.6	1.6	1.6
Total Required Energy (heat duty) for Vaporization (MMBtu/h) [a]	110	110	138	110	110
Minimum Required Total Footprint (ft^2)	32,100	32,100	22,100	20,000	20,400
Costs					
Estimated Capital Expenditure ($ million) [b]	$225.9	$244	$224.1	$218.7	$233.2
Estimated Vaporizer-Related Fuel and Chemical Cost ($ million/yr)	$31.68	$32.46	$4.57	$3.53	$3.53
Estimated Vaporizer-Related Fuel and Chemical Cost Relative to Total Operation Cost	43%	43%	9%	7%	7%
Total costs (initial installation, maintenance, and operation over a 30-year period)	$1,176.3 million	$1,219 million	$362.1 million	$323.7 million	$338.2 million
Energy Requirements					
Regasification Electrical Load Total Power Requirement (MW)	4.54	4.24	8.15	6.29	6.29
Regasification Fuel Consumption Electrical Load (MMscfd)	1,376	1,376	2,656	2,040	2,040
Combustion for Regasification (MMscfd)	15,548	15,548	0	0	0

[62] Main Pass Energy Hub Deepwater Port License Application, Final Environmental Impact Statement, Page 2-12. The IFV considered is seawater based with a shell tube setup.

Table 2 Comparison of LNG Vaporizer Technologies/cont[63]

		Vaporizer Technology				
		SCV Low NO_x Option 1b	SCV/SCR Option 1d	ORV Option 2a	ORV-WHR Option 2b	IFV Boiling/ Condensing Option 3b
Emissions						
Water	Total Seawater Used for Vaporization (gpm)	None	None	124,700 [c]	92,800	92,800
Water	Seawater Discharge Treatment	pH Adjustment	pH Adjustment	Sodium Hypochlorite [d]	Sodium Hypochlorite [d]	Sodium Hypochlorite [d]
Water	Seawater Delta T (Celsius)	NA	NA	10.7	10.7	10.7
Air [e]	PM (tpy)	168.52	189.46	142.8	141.0	141.0
Air [e]	SO_x (tpy)	30.90	11.2	1.1	1.1	1.1
Air [e]	NO_x (tpy)	422.13	251.5	238.4	235.6	235.6
Air [e]	VOC (tpy)	171.22	156.3	153.3	151.9	151.9
Air [e]	CO (tpy)	360.14	247.1	227.9	225.4	225.4

Summary and Conclusions

A number of developments are underway to add offshore LNG options to the North American natural gas supply portfolio. Offshore LNG systems generally fall into two main categories, fixed and floating.

One offshore LNG project is in operation, using a floating design. The Excelerate Energy Bridge project was the first new LNG receiving terminal to be built and operated in the US in more than 20 years and the first offshore LNG receiving terminal in the world. Two Energy Bridge LNG ships were built in South Korea and a third ship is scheduled for delivery in 2006. In addition, a fourth vessel has been recently ordered.

The Energy Bridge Terminal began operation in March 2005[64], which is based on what can be called a highly mobile Floating Storage and Regasification Unit operation. Excelerate has also announced a second project, the Northeast Gateway Energy Bridge to be located in Gloucester, Massachusetts which is expected to be operational in 2007. Beyond the Energy Bridge

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[63] Main Pass Energy Hub Deepwater Port License Application, Final Environmental Impact Statement, Page 2-12. The IFV considered is seawater based with a shell tube setup.

[64] Excelerate Energy: www.excelerateenergy.com

concept, a diverse array of floating design systems is being explored. Despite the availability of infrastructure, competition for LNG cargoes has limited the usage of the terminal to only two cargoes to date.

With respect to fixed structures, the ExxonMobil GBS project offshore of Venice, Italy likely will be the first non-floating offshore terminal put into operation. Fixed systems under development in North America span an array of design and feasibility alternatives and challenges.

While a long history and experience with offshore crude oil operations lends extensive support to offshore LNG developments, ranging from available technologies and designs to marine operations, safety, and environmental protection, the concept of offshore LNG is new and thus encompasses a number of uncertainties especially with regard to environmental impact, floating operations and floating LNG offloading.

There are many considerations for siting offshore LNG import terminals, including shallow water or deepwater locations, near shore or deep offshore locations. In addition to project economics, the regulatory process in the US is the main driver for the choice of location and technology. Final designs depend on marine environment, distance from shore, type of seabed, available pipeline infrastructure, market area being served, and environmental factors. The offshore LNG import terminal may be a continuous baseload facility with significant storage of LNG or natural gas on site or the terminal may operate as an intermittent supplier where the delivered LNG is immediately vaporized and feeds as natural gas into the pipeline with no LNG or natural gas storage associated with the facility.

An issue facing the different types of LNG offshore terminals that propose to use open loop, seawater-based, vaporizers, like ORV and open-loop STVs is impingement and entrainment of marine organisms at the intake. Various mitigation measures and appropriate monitoring protocols have been developed and proposed in the EISs.

Offshore LNG regasification provides a means of meeting growing US natural gas demands. The total average send-out capacity of the proposed offshore terminals is 9.4 Bcf/d or 3.45 Tcf a year and the peak send out capacity is 14.8 Bcf/d or 5.4 Tcf per year. Most of the projected LNG imports required to meet the deficit in natural gas supply by 2025 of 4.8 Tcf per year could be met by the nine proposed offshore terminals, if all the terminals are built.

The decision to “go offshore” with respect to LNG import terminal design and operation hinges on a number of considerations. Geography, marine conditions, seafloor conditions, access to market (pipeline infrastructure) and alternatives for storage (for either LNG or natural gas) all combine to establish economic and commercial hurdles that must be evaluated in order to establish the feasibility of offshore LNG as a choice. While offshore LNG import systems may appear to offer many advantages over onshore systems, they also introduce new challenges, risks, and uncertainties into the LNG supply chain.

The regulatory review and approval process for offshore LNG varies from onshore import terminals in specific ways. The USCG and MARAD are the lead agencies with regard to offshore LNG, as opposed to the FERC for onshore LNG import terminals. Governors in adjacent coastal states can veto or require additional conditions on offshore LNG import facilities, unlike in the case of onshore terminals.

Offshore LNG import systems may provide some operational and cost advantages over onshore import terminals, and may seem to provide alternatives that are viable solutions for certain considerations associated with onshore LNG import terminals. New costs and operational conditions, however, must be weighed and trade-offs evaluated. It is almost certain that additional new offshore LNG import capacity will be developed as part of the US and North American natural gas supply “portfolio”. Competition for LNG supplies is currently an important aspect of completing the LNG value chain. In many cases, short-term price differences between markets have led to under utilized terminal capacity in the US. These price signals can reduce the pressure to incorporate new terminal capacity unless other commercial aspects of the LNG delivery can make them attractive. The choice of location and technology for any one project will be the result of the strongly competitive process at work to establish critical new LNG import capacity for North American natural gas supply diversity and security.

Finally, as mentioned throughout this document, the number of proposed terminals far exceeds forecasts of the necessary terminals that could meet LNG imports. This creates commercial competition to secure LNG supplies and natural gas clients as a means to reduce commercial uncertainty and help make projects viable. The pursuit of terminal licenses generates the option to eventually build a terminal. Not all options will be exercised. For example, some companies are exploring multiple sites to supply the same market and will likely, depending on progress in the licensing process and downstream considerations, drop, divest or abandon the projects.

Appendix A: Summary of US LNG Receiving Terminals: In Operation, Approved, Proposed

Table 3 US LNG Receiving Terminals in Operation in October 2006[8]

Location	Peak Sendout Capacity Bcf/d	Owner
Everett, MA	1.035	Tractebel/DOMAC
Cove Point, MD	1.0	Dominion-Cove Point LNG
Elba Island, GA	1.2	El Paso-Southern LNG
Lake Charles, LA	2.1	Southern Union - Trunkline LNG
Gulf of Mexico (Offshore LA)	0.5	Gulf Gateway Energy Bridge-Excelerate Energy

Table 4 FERC Approved LNG Terminals not in Operation in October 2006[8]

Location	Peak Sendout Capacity Bcf/d	Owner
Hackberry, LA	1.5	Sempra Energy
Freeport, TX	1.5	Cheniere/Freeport LNG Dev.
Sabine, LA	2.6	Cheniere LNG
Corpus Christi, TX	2.6	Cheniere LNG
Corpus Christi, TX	1.1	Vista Del Sol – ExxonMobil
Fall River, MA	0.8	Weaver's Cove Energy/Hess LNG
Sabine, TX	2.0	Golden Pass – ExxonMobil
Corpus Christi, TX	1.0	Ingleside Energy – Occidental Energy Ventures
Corpus Christi, TX	1.0	Ingleside Energy -Occidental Energy Ventures
Logan Township, NJ	1.2	Crown Landing LNG -BP
Port Arthur, TX	3.0	Sempra
Cove Point, MD	0.8	Dominion
Cameron, LA	3.3	Creole Trail LNG -Cheniere LNG
Sabine, LA	1.4	Sabine Pass Cheniere LNG - Expansion
Freeport, TX	2.5	Cheniere/Freeport LNG Dev. - Expansion

Table 5 MARAD/Coast Guard approved Offshore LNG Terminals not in Operation in October 2006[8]

Location	Peak Sendout Capacity Bcf/d	Owner
Louisiana Offshore	1.6	Port Pelican – Chevron
Louisiana Offshore	1.0	Gulf Landing – Shell

Table 6 LNG Terminals proposed to the FERC still in approval process October 2006[8]

Location	Peak Sendout Capacity Bcf/d	Owner
Long Beach, CA	0.7	Mitsubishi/ConocoPhillips-Sound Energy Solutions
LI Sound, NY	1.0	Broadwater Energy - TransCanada/Shell
Pascagoula, MS	1.0	Gulf LNG Energy LLC
Bradwood, OR	1.0	Northern Star LNG -Northern Star Natural Gas LLC
Pascagoula, MS	1.3	Casotte Landing-Chevron
Port Lavaca, TX	1.0	Calhoun LNG -Gulf Coast LNG Partners
Hackberry, LA	1.15	Cameron LNG -Sempra Energy-Expansion
Pleasant Point, ME	0.5	Quoddy Bay, LLC
Robbinston, ME	0.5	Downeast LNG -Kestrel Energy
Elba Island, GA	0.9	El Paso – Southern LNG
Baltimore, MD	1.5	AES Sparrows Point – AES Corp.
Coos Bay, OR	1.0	Jordan Cove Energy Project

Table 7 LNG Terminals proposed to the MARAD/Coast Guard still in approval process October 2006[8]

Location	Peak Sendout Capacity Bcf/d	Owner
Offshore California	1.5	Cabrillo Port -BHP Billiton
Offshore California	0.5	Clearwater Port LLC – NorthernStar NG LLC
Offshore Louisiana	1.5	Main Pass Freeport McMoRan
Gulf of Mexico	1.5	Beacon Port Clean Energyl-ConocoPhillips
Offshore Boston, MA	0.4	Neptune LNG –Tractebel
Offshore Boston, MA	0.8	Northeast Gateway –Excelerate Energy
Gulf of Mexico	1.4	Bienville Offshore Energy Terminal – TORP
Offshore Florida		SUEZ Calypso – SUEZ LNG
Offshore California	1.2	OceanWay-Woodside Natural Gas