ALASKA STAND ALONE GAS PIPELINE /*ASAP*

Greenfield Liquefied Natural Gas (LNG) Economic Feasibility Study

Alaska Stand Alone Gas Pipeline/***ASAP***

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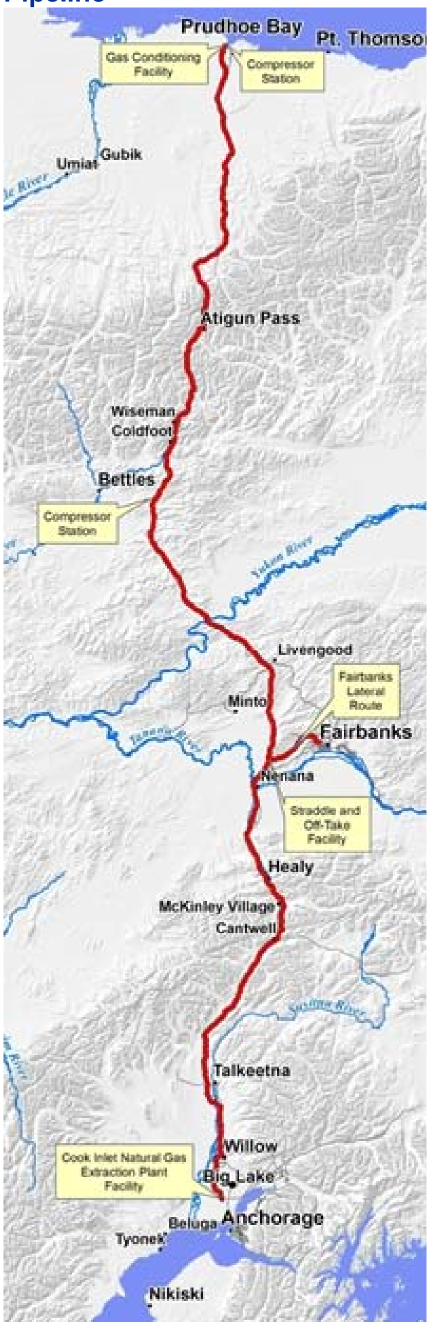
1. INTRODUCTION

Figure 1. **Map of The Proposed Alaska Stand Alone Gas Pipeline**



The objective of this project is to conduct a conceptual-level economic feasibility study of potential LNG facilities that could act as anchor customers for the proposed Alaska Stand Alone Gas Pipeline (Figure 1), which is to transport natural gas from Alaska's North Slope to the Fairbanks and Southcentral regions. A preliminary siting assessment was conducted as part of this project to select general sites to model in the economic analysis, with one site at tidewater in Southcentral, and another in the Fairbanks region. Under the Southcentral scenarios, LNG is produced at a tidewater site that is adjacent to a marine terminal from which the product can be exported to the Pacific Rim Market. Under the Fairbanks scenario, it is assumed that LNG is shipped by rail to a marine terminal at tidewater, where it is then exported to the Pacific Rim Market. Three sizes of liquefaction facilities are modeled based on inlet gas throughput capacities of 250, 500, and 750 MMcfd.

The economic model developed for this project calculates the netback price of gas at North Slope given the projected Pacific Rim price of LNG, and the costs of shipping, storage, liquefaction, and pipeline transport from North Slope. A negative or very low netback price suggests that the North Slope producers will be unable to offer gas for sale at a price that will allow the LNG facility to be economically viable.

The liquefaction facilities modeled in this study all include a separate cogeneration component, in which waste heat from the gas turbines is used to power a steam generator that produces power for sale to the electric power grid. Thus, the economic model also calculates the busbar cost of power at the plant gate.

The Alaska Gasline Development Corporation (AGDC) has contracted this study to develop a project plan for the Alaska Stand Alone Gas Pipeline that would bring gas to the Southcentral region with commencement of pipeline operations in 2016, and alternatively in 2019. AGDC recognizes that even with an anchor customer, the relatively small capacities proposed for the Alaska Stand Alone Gas Pipeline will result in a relatively high cost of service, and that gas intensive industries such as LNG are typically quite sensitive to inlet gas prices. As such, AGDC has additionally requested the assessment of alternative scenarios under which the cost of service for a Stand Alone Pipeline exceeds acceptable levels and hence the pipeline is not constructed. Under these alternative scenarios, it is assumed that the Alaska Stand Alone Gas Pipeline is not built, and that there is no further development of Cook Inlet for natural gas production. Under the import scenarios, Southcentral natural gas demand would be met through the importation of LNG, which would be re-gasified at Nikiski, and sent to the regional pipeline system for distribution or delivery to storage. In these scenarios, the price of re-gasified LNG is calculated.

Table 1 summarizes the export and import scenarios that are modeled in this economic assessment.

Table 1. LNG Export and Import Scenarios

SCENARIO CATEGORY	CONSTRUCTION TYPE/ LOCATION(S)	MAXIMUM THROUGHPUT
LNG Export Scenarios	Greenfield Construction Nikiski Liquefaction Nikiski Marine Terminal	Three scenarios: • 250 MMcfd • 500 MMcfd • 750 MMcfd
	Greenfield Construction Fairbanks Liquefaction Seward Marine Terminal	Three scenarios: • 250 MMcfd • 500 MMcfd • 750 MMcfd
	Brownfield (Kenai Plant refurbishment) Nikiski Liquefaction Nikiski Marine Terminal	One scenario: • 240 MMcfd
LNG Import Scenarios	Greenfield Construction Onshore LNG storage and regasification	One scenario: • 250 MMcfd
	Brownfield Construction (Kenai Plant retrofit) Onshore LNG storage and regasification	One scenario: • 250 MMcfd
	Brownfield Construction (Kenai Plant jetty use) Offshore LNG storage and regasification	One scenario: • 250 MMcfd

An understanding on the LNG export and import markets is essential for appropriate modeling of LNG projects. Section 2 of this report describes the Pacific Rim LNG market, which is generally viewed as the most likely market for Alaskan LNG exports. Section 3 describes the preliminary siting assessment conducted as part of this project, Section 4 describes the economic modeling conducted for this project and modeling results, and Section 5 briefly describes a high-level project schedule.

2. THE PACIFIC RIM LNG MARKET

The Pacific Rim LNG market is defined by the balance of supply and demand. Suppliers of LNG to the Pacific Rim market are described below followed by a listing on LNG importers, representing demand (Sections 2.1 and 2.2, respectively). Subsequent sections address LNG shipping in this market (Section 2.3), LNG contract terms in Pacific Rim markets (Section 2.4), and LNG suppliers that may serve a potential Alaskan demand for LNG (Section 2.5).

2.1 PACIFIC RIM SUPPLIERS OF LNG

The availability of LNG is a key factor for assessing the Pacific Rim LNG market. The export terminal capacities of LNG suppliers are an indicator of their ability to meet and exceed projected regional demand. Regional export terminal capacity represents competition for an Alaskan LNG export terminal, and purchasing choices for an Alaskan LNG import terminal. Gas quality is another important factor that affects arrangements between LNG buyers and sellers, and is discussed after export terminal capacities, below.

2.1.1 Export Terminal Capacities

Table 2 lists total and excess LNG capacity at existing LNG export terminals in the Pacific Rim, as well as total and excess capacity at projects that are currently under construction, planned, and speculative. Committed LNG export volumes were obtained from a list of active and pending LNG supply and purchase agreements (SPAs) and subtracted from "Total Capacity" to estimate available "Excess Capacity" at each terminal. Current and projected total and excess capacity for each terminal is shown for 2010, 2015, and 2020. In 2010 there was about 13.3 Bcfd of total capacity at existing LNG terminals in the Pacific Rim. From 2010 to 2015, very little excess capacity is expected to be available at existing LNG terminals and LNG terminals under construction with the notable exception of Indonesia's Arun and Botang projects (2.3 Bcfd). Indonesia's excess LNG capacity is a result of underproduction of natural gas, which has forced the Indonesian government to divert some gas supplies from LNG export to domestic consumption.[1] This near-term tightness of Pacific Rim LNG supply is likely to be short-term.

Numerous LNG export projects are currently planned in the region, and significant excess capacity could develop by 2015 if these projects are completed. In particular, Australia has an estimated 8.8 Bcfd of excess capacity at planned terminals in 2015, in addition to roughly 0.5 Bcfd of

1 "Indonesia Country Analysis Brief." U.S. Energy Information Administration. U.S. Department of Energy. January 2007. http://www.eia.doe.gov/cabs/indonesia/NaturalGas.htm l (December 29, 2010).

excess capacity from existing trains at the North West Shelf terminal. In 2015, significant excess capacity is also available at existing and/or planned export terminals in Indonesia (5.4 Bcfd), Brunei (1.0 Bcfd), Papua New Guinea (0.9 Bcfd), Russia (0.9 Bcfd), Malaysia (0.8 Bcfd), and Canada (0.7 Bcfd). Overall, an estimated 18.9 Bcfd of excess capacity is available at existing, under construction, and planned LNG terminals in the Pacific Rim in 2015. However, only 5.5 Bcfd (30 percent) of this excess capacity is estimated to be available at existing and under construction terminals. The remainder, roughly 13.3 Bcfd, is shown to be available at planned terminals that may or may not be built.

Determining which of the planned projects in the Pacific Rim come online and which projects are cancelled is beyond the scope of this analysis. However, a conservative estimate is that one-third (4.5 Bcfd) of planned capacity, that is currently un-committed (excess), will eventually be constructed. However, many projects that do eventually come online will likely pre-commit at least some of their capacity through tentative "heads of agreements" (HOAs) prior to final investment decision (FID). Under the scenario where Alaska wishes to import LNG, the state should also consider to pre-committing supply through LNG HOAs with the developers of proposed LNG export projects.

Overall, the potential for excess LNG supplies to the Pacific Rim market suggests a very competitive market in which buyers will have a choice of suppliers. This type of situation increases the risks for investors in Alaskan LNG export projects due to the possibilities that their product will not be able to be sold at prices that provide a sufficient return on their investment.

Table 2. **Pacific Rim LNG Export Terminals: Total and Excess Export Capacities by Country, Status, and Year (MMcfd)**

Terminal	Current Status	Total Capacity			Excess Capacity		
		2010	2015	2020	2010	2015	2020
Australia Pacific LNG	Planned	0	467	467	0	467	467
Beach Energy LNG	Planned	0	132	132	0	132	132
Bonaparte Floating LNG	Planned	0	267	267	0	267	267
Brisbane River LNG	Planned	0	200	200	0	200	200
Browse LNG	Planned	0	1601	1601	0	934	934
Curtis Island LNG	Planned	0	0	534	0	0	534
Darwin LNG	Operational	400	400	400	0	0	0
	Planned	0	867	867	0	867	867
ESG LNG	Planned	0	132	132	0	132	132
Fisherman's Landing	Planned	0	800	800	0	600	600
Gladstone LNG	Planned	0	1093	1093	0	826	826
Gorgon LNG	Under Construction	0	2000	2000	0	0	0
Ichthys	Planned	0	0	1067	0	0	1067
Liquegas Energy	Planned	0	6	6	0	6	6
North West Shelf	Operational	2174	2174	2174	476	543	1223
	Planned	0	587	587	0	587	587

Terminal	Current Status	Total Capacity			Excess Capacity		
		2010	2015	2020	2010	2015	2020
Pilbara LNG	Planned	0	800	800	0	800	800
Pluto LNG	Under Construction	0	573	573	0	73	73
	Planned	0	1145	1145	0	1145	1145
Prelude LNG	Planned	0	0	467	0	0	467
PTT Floating LNG	Planned	0	0	266	0	0	266
Queensland Curtis LNG	Under Construction	0	567	567	0	0	0
	Planned	0	567	567	0	439	439
Southern Cross LNG	Planned	0	187	187	0	187	187
Sunrise LNG	Planned	0	707	707	0	707	707
Timor Sea	Planned	0	400	400	0	400	400
Wheatstone LNG	Planned	0	0	1067	0	0	364
Australia Total		**2574**	**15671**	**19072**	**467**	**9311**	**12690**
Brunei LNG	Operational	959	959	959	64	959	959
Brunei Total		**959**	**959**	**959**	**64**	**959**	**959**
Kitimat Floating LNG	Planned	0	677	677	0	677	677
Canada Total		**0**	**677**	**677**	**0**	**677**	**677**
Abadi Floating LNG	Planned	0	0	667	0	0	667
Arun LNG	Operational	867	867	867	867	867	867
Bontang	Operational	3015	3015	3015	1397	2133	2645
Bukat Floating LNG	Planned	0	0	0	0	0	0
East Kalimantan LNG	Planned	0	667	667	0	667	667
Energy World LNG	Planned	0	67	67	0	67	67
Masela Floating LNG	Planned	0	333	333	0	333	333
Padang LNG	Planned	0	233	233	0	233	233
Sengkang LNG	Planned	0	267	267	0	267	267
Tangguh LNG	Operational	1014	1014	1014	0	0	0
	Planned	0	854	854	0	838	838
Indonesia Total		**4895**	**7315**	**7983**	**2264**	**5403**	**6583**
Malaysia Floating LNG	Planned	0	0	0	0	0	0
MLNG Dua	Operational	1041	1041	1041	0	761	915
MLNG Satu	Operational	1080	1080	1080	0	0	834
MLNG Tiga	Operational	907	907	907	162	0	11
Malaysia Total		**3028**	**3028**	**3028**	**162**	**761**	**1759**
Myanmar LNG	Planned	0	?	?	0	0	0
Myanmar Total		**0**	**?**	**?**	**0**	**0**	**0**
Southland LNG	Speculative	0	?	?	0	0	0
New Zealand Total		**0**	**?**	**?**	**0**	**0**	**0**
Flex Floating LNG	Planned	0	200	200	0	200	200
Liquid Niugini Gas LNG	Planned	0	266	266	0	266	266

Terminal	Current Status	Total Capacity			Excess Capacity		
		2010	2015	2020	2010	2015	2020
Papua New Guinea LNG	Under Construction	0	839	839	0	0	0
	Planned	0	0	880	0	0	853
PNG Floating LNG	Planned	0	399	399	0	399	399
Papua New Guinea Total		**0**	**1705**	**2585**	**0**	**866**	**1719**
Peru LNG	Operational	586	586	586	26	26	26
Peru Total		**586**	**586**	**586**	**26**	**26**	**26**
Kogas LNG	Planned	0	?	?	0	0	0
Sakhalin LNG	Operational	1280	1280	1280	242	216	161
	Planned	0	640	640	0	640	640
Vladivostok LNG	Planned	0	0	666	0	0	666
Russia Total		**1280**	**1920**	**2586**	**242**	**856**	**1467**
Pacific Rim	**Operational**	**13322**	**13322**	**13322**	**3234**	**5504**	**7640**
	Under Construction	**0**	**3979**	**3979**	**0**	**73**	**73**
	Planned	**0**	**14561**	**20175**	**0**	**13283**	**18167**
	Speculative	**0**	**0**	**0**	**0**	**0**	**0**
	Total	**13322**	**31862**	**37467**	**3234**	**18860**	**25880**

Source: Gas Strategies LNG Data Service. Excess capacity calculated by SAIC as total capacity less contracted volumes.

In addition to the countries listed in Table 2, Qatar and other Middle Eastern suppliers can be swing producers of incremental LNG in the Pacific Rim regasification market because of their proximity and economies of scale in LNG production and shipping. Qatar currently functions as a swing producer in the Pacific Rim market but Iran, one of the world's largest natural gas reserve holders, could also play this role in the future. Iran has plans with CNOOC, Repsol, Shell, and Malaysia to develop five LNG projects with a total export capacity of 8.6 BCF/D.[2]

2.1.2 Gas Quality

If Alaska chooses to import LNG from Pacific Rim LNG suppliers, it must assess the interchangeability of the imported LNG stream with the existing gas supply. An Alaskan LNG export facility, on the other hand, may consider producing LNG that meets the gas quality needs of a particular market.

The two most important measurements to consider when assessing gas interchangeability are the gross calorific value and the Wobbe Index number of the gas. The gross calorific value (GCV), also known as the high heating value, indicates the amount of heat released during combustion and is typically measured in British thermal units per standard cubic foot (Btu/Scf). However, two gases with the same GCV can be very different depending on their composition and densities.

[2] *Oil&Gas Journal, April 12, 2010*

The Wobbe Index (WI) number is a more complete indicator of the interchangeability because it measures the degree to which the combustion properties of one gas resemble those of another gas.

The WI is defined as the GCV of the gas divided by the square root of the relative density of the gas: WI = GCV / √relative density. The WI is used to compare the combustion energy output of different composition gases in an appliance. If two fuels have identical Wobbe Index numbers then energy output will also be identical for given pressure and valve settings. Typically variations of up to 5 percent are allowed as these would not be noticeable to the consumer. Table 3 lists the GCV and WI ranges for existing Pacific Rim liquefaction plants, including Alaska.

Table 3. Natural Gas Quality Ranges from Pacific Rim Liquefaction Plants

LNG Export Plant	Wobbe Index (Btu/Scf)	Gross Calorific Value (Btu/Scf)	Methane Content (mol%)
Australia	1,352-1,428	1,150	87.4%
Brunei	1,426	1,133	90.6%
Indonesia-Arun	1,416	1,115	90.7%
Indonesia-Botang	1,417	1,116	91.2%
Malaysia	1,420	1,126	90.3%
Papua New Guinea	1,417	1,116	91.2%
Peru	1,378	1,043	96.8%
Alaska	1,359	1,014	99.7%

Notes: Wobbe and GCV calculated at 60 F/60 F/14.73 psia.
Sakhalin (Russia) quality ranges not available.
Source: 2006-2009 Triennium Work Report

Most Pacific Rim Regasification markets require "rich" natural gas with high GCV and WI numbers, and in most East Asian markets imported LNG must be treated in order to increase the GCV and WI number before it can be injected into the pipeline system (Japan's distribution system, for instance, accepts gas with a GCV from 1,156-1,182 BTU/SCF and a WI number of 1,340-1,467).[3] Imported LNG in Japan is typically treated through the injection of liquid petroleum gas (LPG), usually propane, to increase the GCV and WI number. In order to reduce the amount of downstream treatment, LNG producers in the Pacific Rim often tailor their production streams to the consumption market by producing rich LNG.

The rich quality of Pacific Rim LNG streams may pose a challenge to a potential Alaskan LNG import terminal. The gas in Southcentral Alaska is leaner than existing LNG export streams in Pacific Rim. Depending on the supplier, imported LNG may need to be treated at the regasification plant before it is injected into the pipeline system to assure compatibility with end-use needs. This could be done by blending the regasified LNG with (lean) Cook Inlet gas, injecting nitrogen to dilute the LNG terminal send-out gas, or extracting natural gas liquids (NGLs) from the regasified gas stream.

[3] *International Petroleum Encyclopedia 2005*

Alternatively, imported LNG could be made leaner by stripping NGLs at the liquefaction plant rather than at the import terminal. NGLs, such as propane, butane, and ethane, are present in most Pacific Rim LNG export streams. Because NGLs are denser and have a higher GCV than methane, a natural gas stream with greater NGL content will have a higher GCV and WI number. Worldwide, 10 of 29 liquefaction plants, in 15 countries, are equipped with units to strip NGLs, mainly propane and butane, which are easier to commercialize. However, only three of the 12 existing liquefaction plants in the Pacific Rim strip propane and butane; the Northwest Shelf plant in Australia and the Botang and Arun plants in Indonesia. In the Middle Eastern swing basin only Qatar and Abu Dhabi strip NGLs. The NGL- stripping capacity of planned terminals and terminals under construction are not available.

2.2 PACIFIC RIM IMPORTERS OF LNG

Pacific Rim LNG regasification terminals represent potential entry points for Alaskan LNG. In addition to the traditional onshore regasification terminals, recent advances in shipboard regasification provide new possibilities for LNG entry points, as described after regasification terminal capacities, below.

2.2.1 Regasification Terminal Capacities

Table 4 shows total and excess regasification capacity at operational, under construction, and planned LNG import terminals in Pacific Rim and Indian Ocean regasification markets for 2010, 2015, and 2020. LNG regasification facilities are often built with significant excess capacity to accommodate anticipated growth in demand and to meet the highest anticipated demand during the facilities operating life. As a result, LNG regasification facilities typically operate well under their design capacity on an annual basis. Consequently, excess capacity is not necessarily a measure of unmet demand, nor is it an accurate measure of expected future demand.

Table 4. Regasification Capacity of Pacific Rim and Indian Ocean LNG Import Markets (Million Cubic Feet per Day)

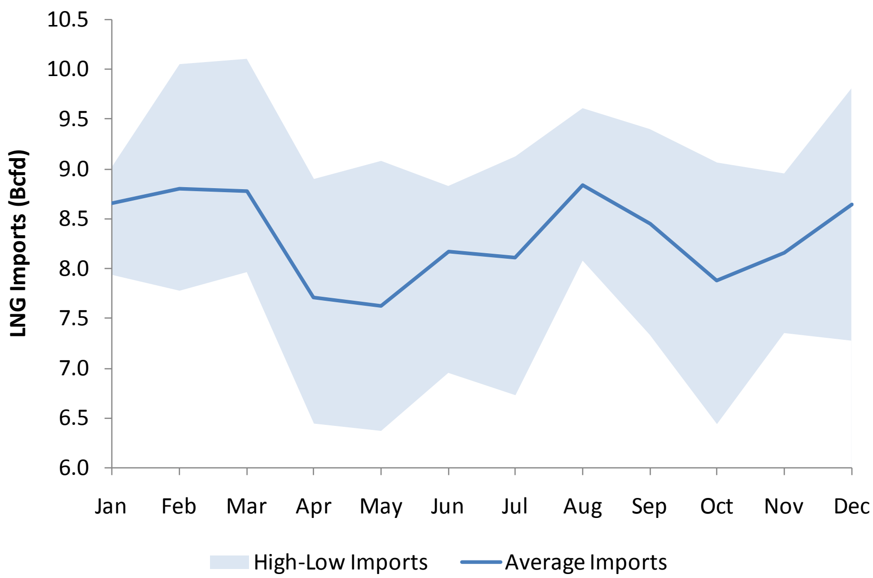
Import Market	Current Status	Total Capacity			Excess Capacity		
		2010	2015	2020	2010	2015	2020
Bangladesh	Planned	0	666	666	0	666	666
	Total	**0**	**666**	**666**	**0**	**666**	**666**
Chile	Operational	358	358	358	132	132	132
	Under Construction	0	368	368	0	368	368
	Planned	0	760	760	0	760	760
	Total	**358**	**1486**	**1486**	**132**	**1259**	**1259**
China	Operational	1281	1281	1281	0	0	0
	Under Construction	0	1584	1985	0	0	0
	Planned	0	3870	5137	0	2415	4168
	Total	**1281**	**6736**	**8403**	**0**	**2415**	**4168**
India	Operational	2534	2534	2534	1534	1120	1120

Import Market	Current Status	Total Capacity			Excess Capacity		
		2010	2015	2020	2010	2015	2020
	Under Construction	0	1333	1333	0	1333	1333
	Planned	0	5333	5333	0	5333	5333
	Total	**2534**	**9199**	**9199**	**1534**	**7785**	**7785**
Indonesia	Planned	0	999	999	0	843	843
	Total	**0**	**999**	**999**	**0**	**688**	**688**
Japan	Operational	20828	20828	20828	12231	11890	14254
	Under Construction	0	365	365	0	365	365
	Planned	0	2042	2442	0	2042	2442
	Total	**20828**	**23234**	**23635**	**12231**	**14296**	**17061**
Malaysia	Planned	0	907	907	0	640	640
	Total	**0**	**907**	**907**	**0**	**640**	**640**
Mexico (West Coast)	Operational	1000	1000	1000	0	0	0
	Under Construction	0	500	500	0	180	180
	Planned	0	4068	4068	0	4068	4068
	Total	**1000**	**5568**	**5568**	**0**	**4248**	**4248**
New Zealand	Speculative	0	0	154	0	0	154
	Total	**0**	**0**	**154**	**0**	**0**	**154**
Pakistan	Planned	0	1335	1335	0	768	768
	Total	**0**	**1335**	**1335**	**0**	**768**	**768**
Philippines	Planned	0	801	801	0	801	801
	Total	**0**	**801**	**801**	**0**	**801**	**801**
Singapore	Under Construction	0	800	800	0	199	199
	Planned	0	270	270	0	270	270
	Total	**0**	**1070**	**1070**	**0**	**469**	**469**
South Korea	Operational	3214	3214	3214	205	368	700
	Under Construction	0	507	507	0	507	507
	Planned	0	400	787	0	400	787
	Total	**3214**	**4121**	**4508**	**205**	**1275**	**1994**
Taiwan	Operational	1157	1157	1157	211	0	196
	Total	**1157**	**1157**	**1157**	**211**	**0**	**196**
Thailand	Under Construction	0	666	666	0	533	533
	Total	**0**	**666**	**666**	**0**	**533**	**533**
Vietnam	Planned	0	399	399	0	399	399
	Total	**0**	**399**	**399**	**0**	**399**	**399**
Pacific Rim	**Operational**	**30372**	**30372**	**30372**	**14312**	**13509**	**16402**
	Under Construction	**0**	**6122**	**6522**	**0**	**3484**	**3484**
	Planned	**0**	**21850**	**23904**	**0**	**19405**	**21946**
	Speculative	**0**	**0**	**154**	**0**	**0**	**154**
	Total	**30372**	**58344**	**60952**	**14312**	**36398**	**41986**

Source: Gas Strategies LNG Data Service. Excess capacity calculated by SAIC as total capacity less contracted volumes.

Excess capacity was estimated by subtracting LNG volumes committed under SPAs or HOAs from total regasification capacity. In 2010, the Pacific Rim/Indian Ocean had roughly 30.4 Bcfd of total regasification capacity at LNG import terminals, of which roughly two-thirds (20.8 Bcfd) was located in the Japanese market. Japanese total LNG regasification capacity is high in excess of demand in order to permit demand flexibility and it is not uncommon for its import terminals to operate at 40-60% of annual capacity.[4] Even during peak demand months, Japan's LNG import terminals operate significantly below capacity (Figure 2). During the highest-demand months Japan imported roughly 10 Bcfd, or just under 50 percent of its total import capacity. LNG regasification demand at a daily level is not available.

Figure 1. Average and High-Low Range of Japanese Import Volumes by Month (Jan. 2005 - Nov. 2010)



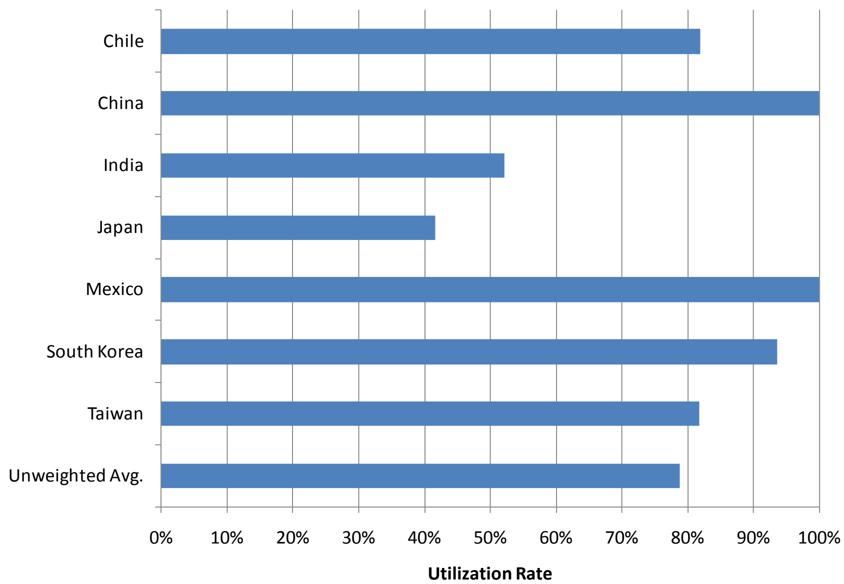
Source: Trade Statistics of Japan, Ministry of Finance (http://www.customs.go.jp/toukei/srch/indexe.htm?M=79&P=0)

Overall, the Pacific Rim/Indian Ocean market had excess capacity totaling 14.3 Bcfd (or about 47 percent of total capacity) at existing terminals in 2010. Looking forward to 2015, total regasification capacity could increase to 58.3 Bcfd with roughly 36.3 Bcfd of excess capacity, including 17.0 Bcfd at existing or under construction terminals, and 19.3 BCFD at planned terminals. The most significant growth markets for LNG regasification capacity between 2010 and 2015 are India (+6.0 Bcfd), China (+5.5 Bcfd), Mexico's West Coast (+4.6 Bcfd), and Japan (+2.3 Bcfd). However, as noted above, total capacity at LNG import terminals is often designed to be much higher than actual import volumes on an annual basis, although this utilization rate varies greatly

[4] *"Natural Gas. Japan. Country Analysis Brief." U.S. Energy Information Administration. September 2010. http://www.eia.doe.gov/cabs/Japan/NaturalGas.html (January 14, 2011).*

from country to country (Figure 3). Chile, China, Mexico, South Korea, and Taiwan all operated at 80 percent or more of annual capacity in 2010, while Japan and India operated between 40 and 55 percent.

Figure 2. LNG Import Terminal Capacity Utilization by Import Country, 2010



Source: Calculated from Table 4.

2.2.2 Potential for Shipboard Regasification

Shipboard LNG regasification technologies allow gas importers to develop LNG import capability at lower cost and within a shorter timeframe than building a conventional onshore terminal. Shipboard regasification also allows importers to site LNG terminals further away from residential, commercial, and industrial zones, and can be particularly useful when coastal real estate is in short supply. However, offshore meteorological and metaocean conditions could limit the reliability of LNG import and regasification operations at the terminal. Furthermore, because LNG storage capacity is limited to size of the cargo space of the shipboard regasification vessel, this technology is typically only cost-competitive for smaller-size import terminals (400 MMcfd or less). Because of the speed of installation, shipboard regasification is often used to serve niche markets or as a short-term import solution while a larger permanent onshore facility is constructed. There are four main configurations of shipboard LNG regasification technology:

- A **Floating Regasification and Storage Unit (FSRU)** is a stationary regasification vessel, typically docked within a port, that receives LNG shipments from a shuttle LNGC via ship-to-ship transfer, stores the LNG in its hull, regasifies the LNG onboard, and sends out the gas via pipeline. A minimum of two vessels (one FSRU and one shuttle LNGC) are needed to accommodate continuous send out.
- A **Shuttle and Regasification Vessel (SRV)** is a mobile regasification vessel that loads LNG at the LNG liquefaction plant, transports the LNG to an offshore site near the import market, regasifies the LNG onboard, and offloads the regasified LNG via a subsea

buoy that interconnects to the gas pipeline system. A minimum of two vessels (both SRVs) are needed for continuous send out.

- **TORP LNG's EasyLNG** is a floating configuration with LNG vaporizers and LNG storage located on separate vessels. EasyLNG consists of a barge mounted with regasification units and a LNGC moored alongside for storage. Shuttle LNGCs deliver LNG to the storage LNGC via ship-to-ship transfer. The storage LNGC pumps LNG to the barge for regasification and send-out to the pipeline system. A minimum of three vessels (a regasification barge, storage LNGC, and shuttle LNGC) are needed for continuous send out.[5]
- **TORP LNG's HiLoad LNG Regasification Unit** is a floating L-shaped structure that docks to the side of a shuttle LNGC for offloading LNG, regasifying, and sending regasified gas to the pipeline system. Due to its compact size, facilities for metering, odorizing, and quality adjustment must be located onshore or on a nearby structure. Because the HiLoad unit lacks storage, it must stay connected to the shuttle LNGC until the full cargo is offloaded and regasified. A minimum of four vessels (two HiLoad units and two shuttle LNGCs) are needed for continuous send out.[6]

Figure 4 displays shipboard regasification options. FSRUs, EasyLNGs and HiLoads are generally cost competitive for medium-to-large volumes and medium-to-long shipping distances. SRVs are generally cost competitive for small-to-medium volumes and short-to-medium distances.

Figure 3. Shipboard Regasification Configurations

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[5] "EasyLNG." TORP LNG. http://www.torplng.com/about_easyLNG.php (January 6, 2011).
[6] "Technology – HiLoad LNG Regasification." TORP LNG

Two companies, Golar LNG and Excelerate Energy, lease FSRUs and SRVs to gas importers. Typical 10- to 20-year time-charter rates range from $120,000 to $150,000 per day. In addition to these fixed daily charges, FSRUs and SRVs also take 1-2% of send-out gas as in-kind payment to power the regasification equipment. Because FSRUs and SRVs are often leased, only the marine infrastructure and send-out infrastructure (jetty, breakwater, send-out pipeline, etc.) must be constructed and financed by the gas importer. As a result, construction costs, which range from $50-200 million depending on the extent of the marine infrastructure needed, are only a fraction of the construction cost of conventional onshore facilities, which typically start at around $400 million. It should be noted that while construction costs are clearly lower for offshore facilities, life-cycle costs, which take in to account annual FSRU/SRV charter costs of $40-50 million per year, may be more or less expensive than a conventional terminal.

TORP LNG's EasyLNG and HiLoad floating regasification configurations are planned at several terminals but no project has yet been realized and estimated costs are not readily available. The primary advantage of these configurations is that they can be executed quickly and can be implemented to meet short-term gas import needs because they do not require the construction of large, expensive storage facilities, nor do they require the long-term charter of FSRUs or SRVs. This concept may be particularly cost-competitive for LNG importers that only desire to supply winter peak demand. However, because the technology has not yet been successfully applied, these configurations have a higher technology risk than more established FSRU and SRV applications.

Table 5 lists eight shipboard regasification projects currently planned in the Pacific Rim/Indian Ocean markets. These projects are generally small-to-mid size terminals, ranging from 199 to 666 MMcfd. Indonesia, which has three planned FSRU projects, is planning to import LNG to serve power plants and industry as domestic gas production diminishes. Bangladesh and Mexico are bringing shipboard terminals online to provide gas supply in the short-term until permanent onshore facilities can be completed. Pakistan's two planned FSRU projects are designed to quickly obtain LNG to allay gas shortages until a permanent solution can be obtained through a gas pipeline from Turkmenistan or Iran.

Table 5. Planned Shipboard Regasification Projects in the Pacific Rim/Indian Ocean

Terminal	Site	Country	Startup Year	Capacity MMCF/D
Sangu floating LNG	Bangladesh (unknown)	Bangladesh	2012	666
Jakarta Bay Floating LNG	West Java Island	Indonesia	2012	199
North Sumatra LNG	North Sumatra	Indonesia	2014	200
Grati Floating LNG	East Java Island	Indonesia	2014	400
Lazara Cardenas	Mexico (unknown)	Mexico	2015	500
Port Qasim Floating	Port Qasim	Pakistan	-	467
Pakistan GasPort	Port Qasim	Pakistan	2011	400
Singapore Floating	Offshore Singapore	Singapore	2012	270

Source: SAIC, Gas Strategies

As developing economies in the Pacific Rim require more energy and existing supply sources are exhausted, there will be increased interest in developing LNG import capabilities, particularly shipboard regasification technologies that offer fast, inexpensive solutions to energy supply shortages. Niche markets may emerge around sites with one or more of the following characteristics:

- Rapidly growing energy demand
- Diminishing indigenous production or unreliable pipeline imports
- High-cost local gas production
- Numerous existing or planned gas-fired power plants
- Existing oil-fired power plants switching fuels to run on lower-cost gas
- Existing coal-fired power plants being phased out due to environmental concerns

2.3 LNG SHIPPING AND REGASIFICATION

Aspects of LNG shipping addressed below include a description of the LNGCs capable of serving an Alaskan LNG terminal and LNG shipping and regasification costs in the Pacific Rim.

2.3.1 LNG Carriers

2.3.1.1 New-Build LNG Carriers Capable of Serving the Alaska Terminal

Optimizing LNG shipping logistics and minimizing transportation costs require that an LNG terminal be capable of accepting a wide range of LNG Carrier (LNGC) sizes. This is true for both LNG import or LNG export terminals. Although, larger capacity LNGCs cost more to build and charter, they reduce the per-unit cost of shipping LNG by increasing economies of scale, particularly over long distances. [7] The key marine constraints at any LNG terminal are the depth of the water at terminal's harbor facilities (i.e., the dock and approach channel) and the diameter of the port's turning circle. Thus, an LNGC's design draft and length overall (LOA) are the key variables that determine whether it can safely call at a particular LNG terminal. Table 6 indicates the main specifications of LNGCs by size category. This table is based on data on LNGCs that were delivered between 1997 and 2010.

Table 6. Main Specifications of LNG Carriers by Size Category

	Micro	Small	Small Conventional	Large Conventional	Q-Flex	Q-Max
Cargo Capacity (1000 cu m LNG)	**18-50**	**65- 90**	**120-149**	**150-180**	**200-220**	**260-270**
LOA (meters)	130-207	216 - 250	270- 298	285- 295	315	345
Beam (meters)	26-29.5	34.0 - 40.0	41.0-49.0	43.0 - 46.0	50.0	53.0-55.0
Draft (meters)	7.0-9.5	9.5 -10.5	11.0 - 12.0	11.0 -12.0	12.0	12.0
Speed (knots)	14.5-16.5	17.5	19.5	20.0	20.0	20.0
Manning (men)	16-22	~27	28-34	28-34	~34	~34
Cost ($ million)*	-	-	~170	~210	~250	~290

[7] Legal requirement stated in Title 46 US Code Chapter 24, Merchant Marine Act, 1920. The cost of building and crewing an LNGC in the US is not cost competitive internationally as evidenced by the fact that there have been no U.S. flagged LNGCs in operation since 2001 (Institute for the Analysis of Global Security)

Note: Includes both Membrane and Moss type LNGCs.
**Approximate costs for LNGCs delivered between 2006 and 2010.*
Sources: SAIC, Poten & Partners, Gas Strategies, MAN Diesel A/S

The two small class 89,900 cu m LNGCs that currently serve the Nikiski LNG terminal – Arctic Spirit and Polar Spirit – each have a draft of about 11 meters and a LOA of roughly 240 meters.[8] The Nikiski site has a depth of 13-14 meters and typical requirements for sea floor clearance are 1-2 meters. Q-flex and Q-max LNGCs, which are currently the largest class of LNGCs on the market, as well as some small and large conventional LNGCs have design drafts of 12 meters. Thus, a small amount of additional dredging may be needed to accommodate larger LNGCs at the proposed site. The turning circle at the Nikiski terminal is approximately 1050 feet (320 meters).[9] In order to accept larger LNGCs of the small conventional size or larger, the turning circle would need to be expanded. To maintain a 25 percent clearance the turning circle would have to be expanded to at least 338 meters for a small conventional LNGC, to at least 356 meters for a large conventional LNGC, and to roughly 394 meters for a Q-flex LNGC and 431 meters for a Q-max LNGC.

Another important limiting factor is the capacity of the LNG storage tanks at the Nikiski terminal. Currently, the terminal has a storage capacity of 105,000 cu m which is enough to support the 89,900 cu m LNGCs that currently call at the 200 MMcfd terminal as well as a 5% tank heel and a 3-day reserve. In order to accept larger-size LNGCs, storage capacity would need to be expanded to accommodate the ship's full cargo plus the required tank heel and reserve capacity. Assuming that the terminal's throughput capacity remains fixed at 200 MMcfd, storage would need to be expanded to at least 160,000 cu m in order to accommodate a small conventional (138,000 cu m) LNGC, at least 200,000 cu m to accommodate a large conventional (180,000 cu m) LNGC, at least 230,000 cu m to accommodate a Q-flex (210,000 cu m) LNGC, and at least 275,000 cu m to accommodate a Q-max (260,000 cu m) LNGC. Increasing LNG throughput at the terminal would increase storage requirements by increasing the 3-day reserve volumes and the 5% tank heel.

2.3.1.2 Ice Class Requirements

The two LNGCs serving the Nikiski LNG terminal - the Arctic Spirit and Polar Spirit - are both "Ice Class C" (ICE-C) carriers, which means their hulls and frames (scantlings) were constructed to withstand very light ice conditions up to 0.4 meters (15.6 inches) in thickness. A larger, new-build LNGCs operating out of the same terminal would also be expected to meet similar ice requirements by reinforcing the ship's hull, designing the ship's equipment to operate at very low temperatures, and modifying overall ship design to allow the crew to perform necessary functions

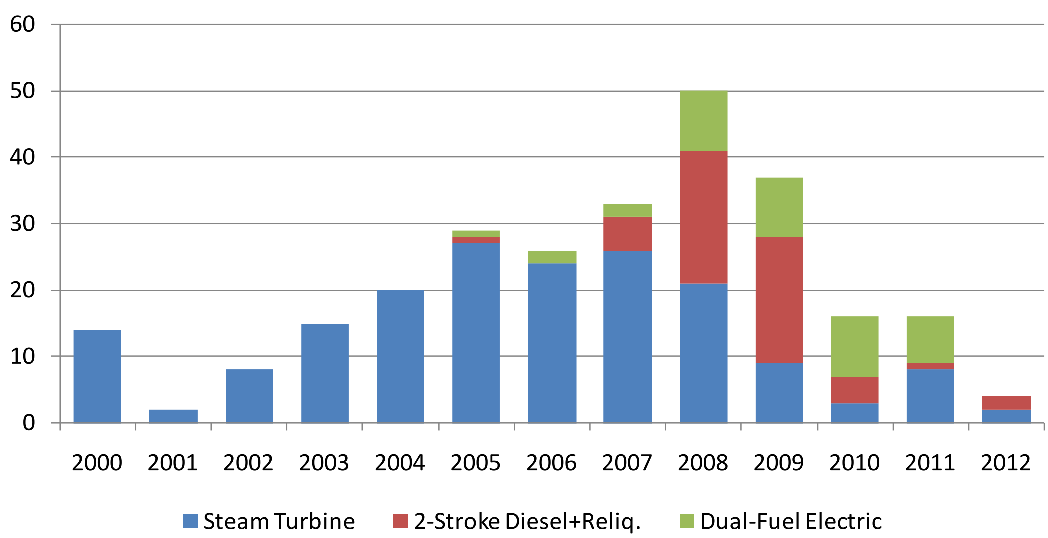
8 "Polar Spirit." GAS-Carriers > 75,000 CBM. Auke Visser´s International Super Tankers. http://www.aukevisser.nl/supertankers/gas/id493.htm (December 30, 2010).
9 "Cook Inlet PPOR-02 Central Area –Physical and Operational Characteristics."NUKA Research & Planning Group, LLC. June 2008. http://www.dec.state.ak.us/spar/perp/cookinletpor/cippormap02.pdf (December 30, 2010).

at low temperatures.[10] These modifications will add approximately 5-10 percent to the cost of a new construction LNGC.[11] In addition, the modifications will also add weight to the ship and may alter the hull shape design, thus increasing fuel consumption by a small degree.

2.3.1.3 Engine options for New Build LNGCs

Historically, LNGCs have used steam turbine propulsion, utilizing the cargo's natural boil-off gas (N-BOG) and heavy fuel oil (HFO) to power the ship. Despite the inefficiency of steam turbine engines (roughly 29% at full load when steaming and 25% for electric power production), they have continued to be used in newer LNGCs due to their low maintenance, acceptable capital cost, and the ease with which they consume N-BOG thus eliminating the need for onboard BOG reliquefaction. In recent years, however, more LNGCs have been constructed with LNG reliquefaction facilities that eliminate losses due to N-BOG, and allow the ships to run on more efficient two-stroke or four-stroke diesel engines, which have dominated propulsion and electric power generation in all segments of merchant shipping (except LNG shipping) since the 1970s (Figure 5). These engines have efficiencies of about 48% for propulsion and 43% for electric power generation. However, these engines can only run on liquid fuels such as HFO or marine diesel and the LNGC must consume a substantial amount of electric power for N-BOG reliquefaction, thus increasing fuel needs. As a result, diesel-power LNGCs with LNG reliquefaction may only be advantageous when selling LNG into a high price natural gas market, such as Japan or Korea, where the delivered LNG price is higher than the price of liquid fuels.

Figure 4. New-Build LNGCs by Engine Type and Delivery Year



Source: Gas Strategies LNG Data Service

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[10] *"ICE-C." DNV Managing Risk. http://www.dnv.com/industry/maritime/servicessolutions/classification/notations/additional/icec.asp (December 30, 2010).*

11 Ice Class Shipping Review; TankerOperator; http://www.tankeroperator.com/pastissues/TOSept06.pdf; September 2006

A third propulsion option for new-build LNGCs, dual-fuel electric engines, are more efficient than traditional steam turbine engines and allow the LNGC to run on both boil-off gas and liquid fuel. The efficiency of a dual-fuel electric engine is approximately 43% for propulsion and 47% for electric power generation. This dual-fuel ability is advantageous because the LNGC can run fully on N-BOG and additional forced boil-off gas (F-BOG) when the energy equivalent price of LNG in the sale market is cheaper than HFO. If the price of HFO is cheaper than the LNG sale price, then LNGC can run on N-BOG and HFO. Thus ship operators with dual-fuel electric engines can arbitrage between fuel prices to minimize transportation costs.

In addition to being more efficient than traditional steam turbines, dual-fuel electric engines and diesel engines with reliquefaction, both have lower capital costs with each costing roughly $6 million less when installed on a 200,000 cu m LNGC (Table 7).

Table 7. LNGC Engine Efficiencies and Capital Costs by Type

Engine Type	Propulsion Efficiency	Electric Power Efficiency	Cost* (2011 US $)
Steam Turbine	25%	29%	$22 million
Two-Stroke Diesel + Reliquefaction	48%	43%	$16 million
Dual-Fuel Electric	43%	47%	$16 million

**Assuming a 200,000 cu m LNGC.*
Sources: Thijssen, Barend. "Dual-fuel-electric LNG carriers." Wartsila presentation. Hamburg, Germany. September 27, 2006.
http://www.thedigitalship.com/powerpoints/SMM06/lng/Barend%20Thijssen,%20wartsila.pdf
B. Gupta & K. Prasad. "Various Propulsion Alternatives." Page 105
http://www.dieselduck.ca/machine/02%20propulsion/LNG%20Transport%206%20of%207.pdf

It is possible that underwater noise in Cook Inlet will be regulated in the future, which may affect LNGC engine requirements. Regulated protective zones for Beluga whales have been proposed by the U.S. Commerce Department. The International Maritime Organization's (IMO) Marine Environmental Protection Committee (MEPC) is also studying underwater noise effects on marine life.

2.3.2 Shipping Costs

Shipping costs are generally composed of two primary components, a contractually firm charter rate and a variable rate that covers the cost of bunker fuel.

2.3.2.1 LNGC Charter Rates

Long-term LNGC time-charter rates vary from ship to ship based on a number of factors including the ship's size, original construction price, vintage, and financing. In 2009 long-term time charter rates for small conventional LNGCs rose to $68,000 per day, up 17 percent from an average of $58,000 per day in 2004 due to an increase in shipbuilding costs.[12] Table 8 provides approximate long-term LNGC charter rates based on recent quotes from shippers and average costs of new build LNGCs by size category. Time-charter rates are fixed and do not include fuel costs or port fees.

Table 8. Estimated LNGC Daily Time Charter Rates and Annual Costs by LNGC Size, 2011 US $

Size Category	Mid-Point Capacity (cu m)	Charter Rate ($ per day)	Annual Cost
Micro	34,000	$25,000	$9 million
Small	78,000	$51,000	$19 million
Small Conventional	138,000	$70,000	$26 million
Large Conventional	165,000	$75,000	$27 million
Q-flex	210,000	$83,000	$30 million
Q-max	265,000	$90,000	$33 million

Source: SAIC World LNG Model (Run: 1/3/2011)

2.3.2.2 Variable LNG Shipping Costs

Table 9 shows LNG transportation costs to existing and potential Pacific Rim and Indian Ocean regasification markets based on shipping distance and the size and number of LNGCs needed to transport a given baseload volume (500 MMcfd) over the course of one year. Shipping costs were calculated using estimations of long-term LNGC charter rates, average ship speeds, steam-turbine engine efficiencies, natural boil-off gas rates, natural boil-off gas costs of $2.50 per MMBtu, and estimated HFO and marine diesel costs when crude is $80 per barrel. Unit shipping costs are expressed in constant 2011 U.S. dollars per million British thermal unit (US $/MMBtu).

The two most important factors driving differences between shipping costs are 1) the distance from the Alaska export terminal to the import terminal and 2) the capacity of the largest LNGC that can call at the import terminal, which is a function of port characteristics and the terminal's storage capacity. Import terminals that are farther from Alaska have longer round-trip delivery times, thus requiring more LNGCs and/or larger LNGCs in order to deliver the same amount of LNG over a one year span. Thus, far away export destinations typically have higher per-unit shipping costs compared to closer destinations. However, the ability of an import terminal to accept larger LNGCs and thus achieve greater economies of scale could allow a far away import terminal to have a lower unit cost than a closer terminal that may require two smaller LNGCs to deliver the same volume. Table 9 assumes that the Alaska terminal would modify its port facilities and expand storage capacity if necessary in order to optimize shipping costs to its LNG buyers. This assumes these modification and expansions to the terminal would be less expensive than chartering extra LNGCs over the project's 20-year life span.

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[12] *"LNG city charter price slides on low demand." Bloomberg News. March 22, 2010. http://bestshippingnews.com/shipping-news/lng-city-charter-price-slides-on-low-demand/ (December 30, 2010).*

Table 9. **Shipping Costs, Distances, and Number and Capacity of LNGCs to Transport 500 MMCFD of LNG from Alaska to Select Markets, 2011 US $/MMBtu**

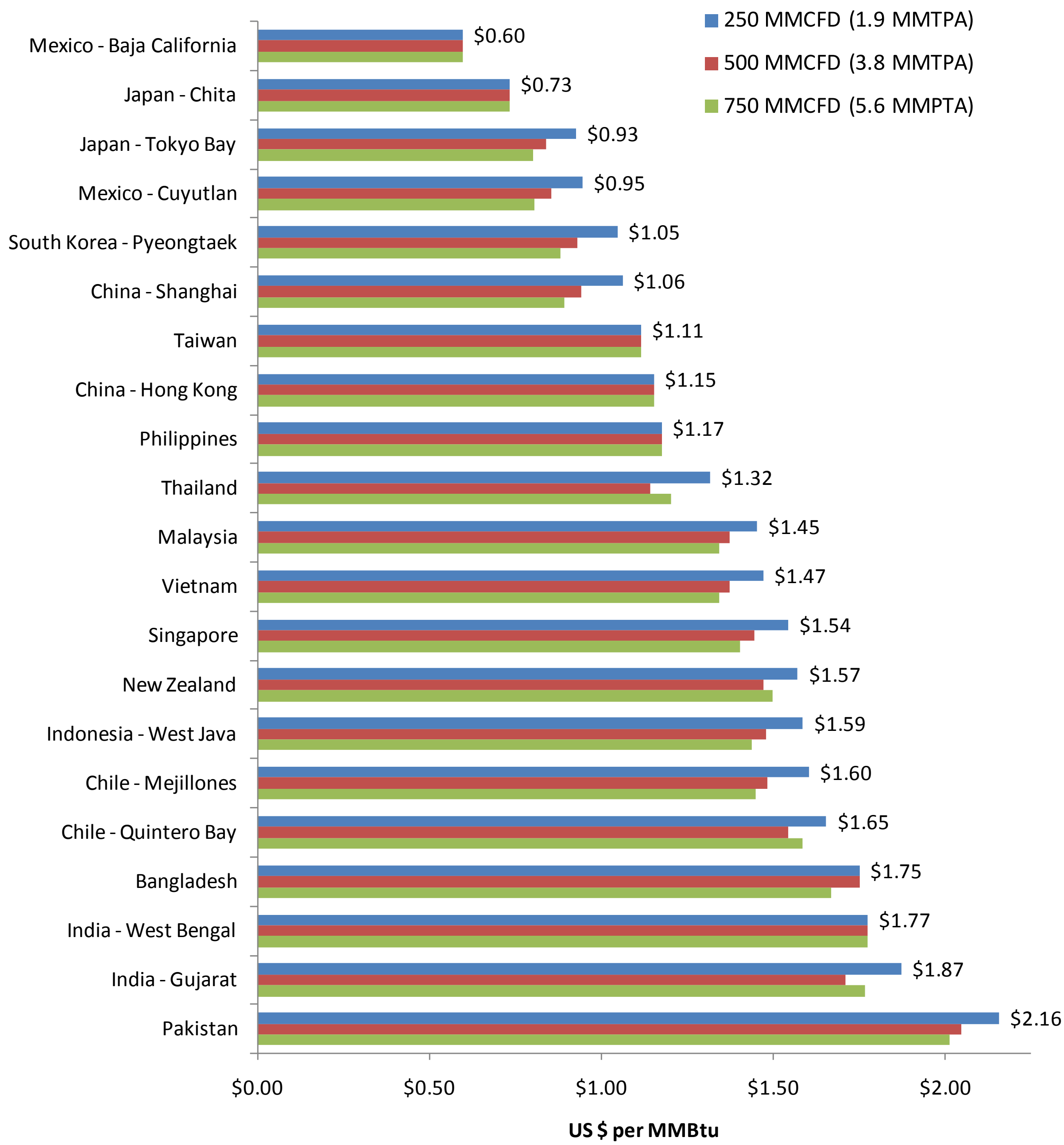
Export Destination	Unit Cost $/MMBtu	Distance (nautical miles)	Max LNGC at Import Terminal	LNGCs Needed (# x Capacity)
Mexico - Baja California	$0.60	2,308	216,000 cu m	2 x 175,000 cu m+
Japan - Chita	$0.73	3,682	266,000 cu m	2 x 254,000 cu m+
Japan - Tokyo Bay	$0.84	3,274	216,000 cu m	3 x 154,000 cu m+
Mexico - Cuyutlan	$0.85	3,351	180,000 cu m*	3 x 157,000 cu m+
South Korea - Pyeongtaek	$0.93	4,032	266,000 cu m	3 x 182,000 cu m+
China - Shanghai	$0.94	4,118	266,000 cu m	3 x 186,000 cu m+
Taiwan	$1.11	4,524	160,000 cu m	4 x 151,000 cu m+
Thailand	$1.14	6,227	266,000 cu m	3 x 266,000 cu m+
China - Hong Kong	$1.15	4,775	180,000 cu m*	4 x 158,000 cu m+
Philippines	$1.17	4,961	180,000 cu m*	4 x 163,000 cu m+
Malaysia	$1.37	5,613	180,000 cu m*	5 x 146,000 cu m+
Vietnam	$1.37	5,629	180,000 cu m*	5 x 146,000 cu m+
Singapore	$1.44	6,115	180,000 cu m*	5 x 157,000 cu m+
New Zealand	$1.47	6,295	170,000 cu m	5 x 161,000 cu m+
Indonesia - West Java	$1.48	6,435	180,000 cu m*	5 x 164,000 cu m+
Chile - Mejillones	$1.48	6,471	180,000 cu m*	5 x 165,000 cu m+
Chile - Quintero Bay	$1.54	6,933	180,000 cu m*	5 x 176,000 cu m+
India - Gujarat	$1.71	8,542	220,000 cu m	5 x 212,000 cu m+
Bangladesh	$1.75	7,624	180,000 cu m*	6 x 159,000 cu m+
India - West Bengal	$1.77	7,757	180,000 cu m*	6 x 162,000 cu m+
Pakistan	$2.05	8,994	180,000 cu m*	7 x 159,000 cu m+

**No data was available on maximum LNGC capacity so 180,000 cu m was assumed.*
Source: SAIC World LNG Model Run (1/3/2011)

Another determinant of LNG shipping costs is the volume of LNG shipped. Table 9 shows shipping costs and parameters for the transport of 500 MMcfd per year. Typically, if an increase in LNG volume can be accommodated using the same number of LNGCs but with a larger capacity, the per-unit shipping costs will fall as the route takes advantage of greater economies of scale. However, at some point, LNGC capacity cannot be increased due to restrictions at the import terminal (water depth, turning circle, ship channel width, etc.) or due to limits on size of existing LNGC designs (up to 270,000 cu m). Figure 6 shows how shipping costs change with annual contract volume. Shipping costs are shown in constant 2010 U.S. dollars per MMBtu for three volumes of 250 MMcfd, 500 MMcfd and 750 MMcfd

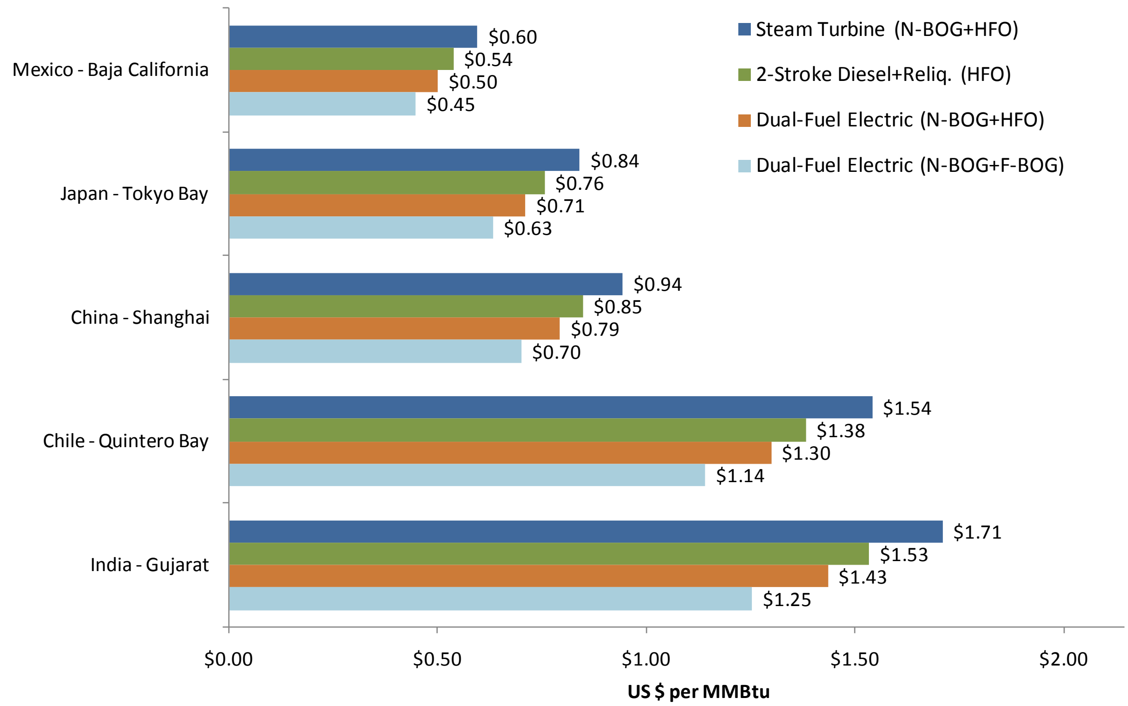
Another key determinant of shipping cost is engine type because different engine types will require different types and quantities of fuel to propel the same size LNGC. In addition to fuel usage, different engine types also have different capital, maintenance, and non-fuel operating costs, which are reflected in the LNGC's charter rates. As discussed previously, there are three engine types that have been installed in recent new-build LNGCs: steam turbine engines that run on heavy fuel oil (HFO) and natural boil-off gas (N-BOG), two-stroke diesel engines with onboard reliquefaction plants that run on HFO or marine diesel, and dual-fuel electric engines that can run on N-BOG and HFO, or N-BOG and forced boil-off gas (F-BOG). Figure 7 shows estimated LNG shipping costs from Alaska to selected regasification markets by engine type.

Figure 5. Estimated LNG Shipping Costs from Alaska to Pacific Rim/Indian Ocean Regasification Import Markets by LNG Volume, 2010 US $/MMBtu



Note: Assuming Steam Turbine LNGC
Source: SAIC World LNG Model (Run: 1/3/2011)

Figure 6. Estimated LNG Shipping Costs from Alaska to Select Regasification Markets by Engine Type, 2011 US $/MMBtu (Volume = 500 MMcfd)



Source: SAIC World LNG Model (Run: 1/3/2011)

Figure 7 is based on energy prices if world oil prices trade at roughly $80 per barrel in constant 2011 dollars. At this level HFO prices are estimated to be roughly $470 per metric ton, marine diesel prices are estimated to be roughly $700 per metric ton, N-BOG costs are estimated to be $2.50 per MMBtu, and F-BOG costs (i.e. CIF LNG prices in Pacific-Rim regasification market) are estimated to be $12.50 per MMBtu. Given these inputs, the most cost-effective engine type for LNG shipping is a dual-fuel electric engine running on N-BOG and F-BOG. This configuration offers a roughly 25 percent cost savings versus the traditional steam engine. A dual-fuel electric engine running on N-BOG and HFO offers a cost savings of roughly 15 percent and a two-stroke diesel engine with LNG reliquefaction offers a 10 percent savings versus the steam turbine engine.

2.3.3 Regasification Costs

LNG regasification cost vary from terminal to terminal based on a number of factors including capital costs, financing rates, capacity, and the age of the terminal but are typically in the range of $0.50-1.00 per MMBtu in constant 2011 US dollars. The more expensive terminals are in Japan where high land costs and the need to maintain large LNG storage capacity increase required investment costs. Typically, higher-throughput import terminals will have lower per-unit regasification costs because capital charges are spread out over a greater import volume.

Regasification terminal costs may also include the cost of the gas header system for access to multiple redelivery pipelines in order to follow peak load (intrinsic value) and to increase their arbitrage value (extrinsic value). In the U.S., some Gulf Coast regasification facilities can access 10 or more take-away pipelines. Such additional connections can add an additional $0.25 to $0.50/MMBtu (2011 dollars) to regasification costs.

2.4 LNG CONTRACT TERMS IN THE PACIFIC RIM MARKET[13]

The contractual cornerstone of LNG trade (in the Pacific Rim and other regasification markets) is the LNG Sale and Purchase Agreement (SPA). The LNG SPA apportions the risks and rewards along the LNG value chain at the intersection of upstream production and liquefaction and downstream regasification and distribution. The key components of long-term or short-term LNG contracts are the quantity, price, duration, and transportation responsibility (FOB, CIF or ex-ship).

2.4.1 Quantity

Long-term LNG contracts typically include an “annual contract quantity” (ACQ), which specifies the quantity of LNG that the buyer must purchase and take or pay for if not taken. This quantity is usually expressed in millions of British thermal units (MMBtus). Most long-term contracts allow for the “buildup” of deliveries during the initial period of the contract. During the buildup period delivered quantities are lower than the ACQ to allow the importing market to absorb and find buyers for the new supply and to accommodate potential delays in the completion of the liquefaction plant. These build up volumes are not subject to take-or-pay requirements. Once the buildup period has ended the ACQ remains constant over the duration of the contract but may be subject to some adjustments including:

- *Volume flexibility provisions*, which allow the buyer to reduce the ACQ obligation by a fixed amount, usually about 5%. Some contracts limit the number of adjustments or the aggregate adjustments that the buyer can make during the duration of the contract;
- *Round up/round down provisions*, which address uneven annual quantities due to LNG shipments that come before or after the actual turn of the contract year due to scheduling issues;
- *Excess quantity provisions*, which govern who has the rights to excess quantities from an LNG liquefaction plant that performs better than expected or when a buyer in a multiple-buyer project reduces imports within its take-or-pay limits.
- *Make up quantity provisions*, which may occur when the LNG buyer is unable to take some or all of the take-or-pay portion of its ACQ. In this case, the LNG buyer must still pay the LNG seller a price (equal to or less than the contract price) for the untaken LNG. In return, the seller may be required to offer the buyer deliveries equivalent to the untaken volumes at a later date. In some cases there may be a limit after which makeup quantities must be taken or forfeited.

[13] *This section is a summary of key points from the following resource: Tusiani, Michael. “LNG: A Nontechnical Guide.” PennWell Books, 2007. Page 319-325.*

- *Redestination flexibility*, may be provided to a buyer with a dedicated annual volume under a long-term contract in order to accommodate volume flexibility and make-up quantity provisions. However, such rerouting flexibility is provided if the seller does not place themselves in self-competition that is such a cargo would not compete with other seller deliveries at specified import terminals.

2.4.2 Contract Duration

Traditionally LNG contracts have had durations of 20 years or longer in order to give the LNG buyer security of supply and to give the LNG buyer stable cash flow that allows an appropriate return on investment and can secure long-term financing. Security of supply is particularly important for Far East Asian LNG importers, such as Japan, Korea, and Taiwan that have scarce indigenous resources and are highly dependent on imported fuel. While average contract durations in the Atlantic Basin have shortened in recent years, Pacific Rim markets are expected to continue contracting LNG on a long-term basis.

The primary terms of the contract do not include the buildup period, which is treated separately. Often, provisions are included that allow durations can to be extended for a certain period (e.g. 5 years) by either the buyer or seller. This extension may be on the same terms as in the initial term of the contract, or may allow limited reopening of key commercial terms (price or quantity).

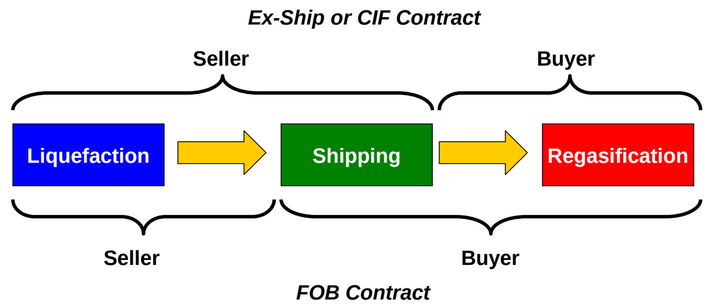
2.4.3 Gas Quality

LNG SPAs specify a range of acceptable gas quality (gross calorific value and/or Wobbe Index limits). Contracts typically give the LNG buyer the right to reject a cargo of off-quality LNG, but this right is rarely exercised. Instead, contracts may include provisions that mandate that the seller reimburse the buyer for the costs of treating the LNG to bring it into the specified gas quality range. Traditional Pacific Rim regasification markets such as Japan, South Korea, and Taiwan require rich LNG streams (i.e. with high energy content). Some major LNG sellers are now modifying their LNG liquefaction plants to produce differentiated streams of LNG to enable them to customize LNG blends for different markets.

2.4.4 Transportation

LNG SPAs specify the party responsible for arranging for the delivery of the ACQ. Most SPAs specify delivery on an “ex-ship” or “CIF” (Cost, Insurance, and Freight) basis meaning that the seller has responsibility for transporting LNG volumes from the liquefaction plant to the buyer’s import terminal. Delivery on an “FOB” (Free on Board) basis, on the other hand, gives shipping responsibility to the buyer (Figure 8). Under an ex-ship or CIF contract, the buyer is responsible for providing a safe port at the LNG import terminal at which LNGCs can enter and exit under all normal conditions. The seller is required to ensure that the LNGCs used are compatible with this berth, have up-to-date measurement equipment, are of the proper size, and satisfy the operating and quality standards specified in the SPA.

Figure 7. Seller vs. Buyer Responsibilities Under Ex-Ship/CIF and FOB Contracts



2.4.5 Other Terms and Conditions

Other terms and conditions that apply to long-term LNG contracts have much in common with contracts in other markets. Such terms relate to cargo scheduling, invoicing and payment, LNG quantity measurement, title transfer, force majeure conditions, dispute resolution, and events of default, including the allocation of liabilities, liquidated or stipulated damages, early termination damages, and choice of law.

2.5 LNG SUPPLIERS FOR SERVING ALASKA

Table 2 identified several existing, under construction, and planned LNG export projects that currently have uncommitted (i.e. excess) capacity over the next 5 and 10 years. In particular, the table identified significant excess capacity at terminals in Australia, Indonesia, Brunei, Papua New Guinea, Russia, and Malaysia. Estimated total excess capacity for 2015 is provided in Table 10. The table shows that approximately 5.5 Bcfd or 30% of this excess capacity is from existing facilities.

Table 10. 2015 Excess Capacity for Pacific Rim LNG Export Countries (Bcfd)

Export Country	Total	At Existing Terminals
Australia	9.3	0.5
Indonesia	5.4	3.0
Brunei	1.0	1.0
Papua New Guinea	0.9	0.0
Russia	0.9	0.2
Malaysia	0.8	0.8
Canada	0.7	0.0
Total	**19.0**	**5.5**

Source: Table 2.

It is not clear whether all of the planned capacity will actually come online as final investment decisions on several of Pacific Rim projects have not yet been made. Several of Australia's planned projects face economic concerns because they utilize new liquefaction technologies (floating LNG) or more expensive feed gas production (coalbed methane), and Indonesia's planned projects face political risk due to disputes over whether feedgas should be used domestically or exported.[14] Nevertheless, at least some new capacity is likely to become available in the Pacific Basin over the next 5-10 years.

2.5.1 Pacific Rim LNG Production Costs

LNG production costs, which include upstream natural gas production and liquefaction, vary from terminal to terminal based on a number of factors including the technical complexity and cost of gas extraction, the cost of labor and materials, and financing rates, among others. Providing LNG production cost estimates by terminal would be beyond the scope of this analysis. Historically, LNG production costs, including gas production, liquefaction, and royalties, have ranged from roughly $2.00-2.50 per MMBtu.[15, 16, 17, 18] Recent cost inflation in construction costs for LNG export projects (upstream and liquefaction) are likely to significantly increase these per-unit production costs. Of the export projects in Pacific Rim market, Australia and Russia are likely to have the most expensive production and liquefaction costs due to higher labor costs and the technical difficulty of the projects. Indonesia, Brunei, Papua New Guinea, and Malaysia are likely to have less expensive costs.

2.5.2 LNG Shipping Costs to Alaska from Pacific Rim Suppliers

Table 11 estimates LNG shipping costs to Alaska from Pacific Rim LNG suppliers given an annual import volume of 250 MMcfd. These estimates assume that the Alaska LNG import terminal will utilize the two existing 89,900 cu m LNGCs – the Arctic Spirit and Polar Spirit – and add additional new- build ice class LNGCs as needed. According to annual reports from Teekay Corporation, the current owner of the two LNGCs, the company earned $38.3 million in 2008 by chartering out the two vessels to the Marathon Oil/ConocoPhillips joint venture for use at the Nikiski LNG terminal.[19] These earnings correspond with a time-charter rate of roughly $52,500 per day for each vessel. In 2009, however, Teekay reported that a reduction in the time-charter rate for the Arctic Spirit had led to a loss of $6.9 million over the previous year.[20] These reduced earnings correspond with a much lower time-charter rate of $33,500 per day. The $33,500 per

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[14] *"2015-2035 LNG Market Assessment Outlook for the Kitimat LNG Terminal." Prepared for KM LNG Operating General Partnership. Poten & Partners. October 2010.*

[15] *IELE 2003. Slide 4. http://www.iaee.org/documents/washington/Sophie_Meritet.pdf*

[16] *EIA Global LNG Study 2004. Table 31 Table 31. http://www.ogj.com/index/article-display/204715/articles/oil-gas-journal/volume-102/issue-19/transportation/distance-continues-to-drive-lng-costs-for-us-delivery.html*

[17] *BG Group 2004. Table 4. http://www.ogj.com/index/article-display/204715/articles/oil-gas-journal/volume-102/issue-19/transportation/distance-continues-to-drive-lng-costs-for-us-delivery.html*

[18] *Rice University, 2004. Slide 20. http://bakerinstitute.org/programs/energy-forum/publications/docs/GSP_WorldGasTradeModel_Part1_05_26_04.pdf*

[19] *Teekay Corporation 2008 Annual Report on Form 20-F. page 36. http://www.teekay.com/documents_root/News%20Releases/TKC_20-F_Dec_2008%20_1pm_%20version.pdf (January 18, 2011).*

[20] *Teekay Corporation 2009 Annual Report on Form 20-F. page 37. http://www.teekay.com/documents_root/News%20Releases/TK_2009_Annual_Report_on_Form_20F.pdf (January 18, 2011).*

day time-charter rate, along with assumptions about HFO prices when oil is at $80 per barrel, were used to estimate the shipping costs for the first Arctic Spirit and Polar Spirit in Table11. If more than two LNGCs are needed for the project, an estimated time charter rate of $56,000 per day was used for the additional new-build LNGCs.

Table 11. Estimated LNG Shipping Costs, Distances, and LNGC Number and Sizes Needed to Deliver 250 MMCFD to Alaska, 2011 US $/MMBtu

Export Destination	Unit Cost $/MMBtu	Distance (nautical miles)	Max LNGC at Import Terminal	LNGCs Needed (# x Capacity)
Canada - Kitimat	$0.42	1,000	89,900 cu m	2 x 89,900 cu m
Russia - Sakhalin	$0.58	2,473	89,900 cu m	2 x 89,900 cu m
Indonesia - Tangguh	$1.31	5,190	89,900 cu m	4 x 89,900 cu m
Brunei	$1.35	5,580	89,900 cu m	4 x 89,900 cu m
Papua New Guinea	$1.35	5,594	89,900 cu m	4 x 89,900 cu m
Malaysia	$1.35	5,613	89,900 cu m	4 x 89,900 cu m
Indonesia - Botang	$1.59	5,746	89,900 cu m	5 x 89,900 cu m
Peru	$1.61	5,916	89,900 cu m	5 x 89,900 cu m
Indonesia - Sulawesi	$1.61	5,918	89,900 cu m	5 x 89,900 cu m
Australia- Gladstone	$1.61	5,926	89,900 cu m	5 x 89,900 cu m
Australia- Darwin	$1.62	6,035	89,900 cu m	5 x 89,900 cu m
Indonesia - Arun	$1.70	6,708	89,900 cu m	5 x 89,900 cu m
Australia- NW Shelf	$1.70	6,719	89,900 cu m	5 x 89,900 cu m

Source: SAIC World LNG Model (Run: 1/3/2011)

Table 11 shows that if only the Arctic Spirit and the Polar Spirit are used without adding additional LNGCs, the LNG must be from either the planned LNG export project in Kitimat, Canada or the existing LNG terminal in Sakhalin. From Sakhalin, the two 89,900 cu m would make roughly 26 trips per year each with little downtime between trips. From Kitimat, the two LNGCs would make the same number of trips but would have significant downtime between trips.

2.5.3 LNG Pricing in the Pacific Rim Import Market

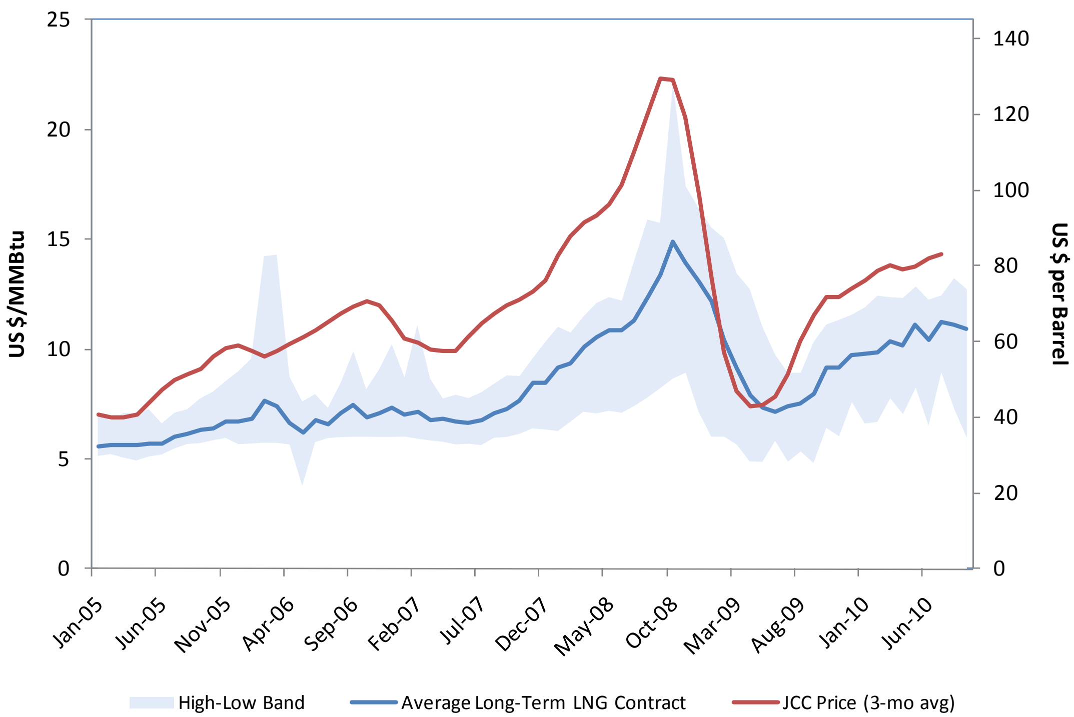
The Pacific Rim LNG market is dominated by the traditional import markets of Japan, South Korea, and Taiwan, which are characterized by a lack of indigenous energy supplies and a high dependence on imports of fossil fuels. As a result, these countries prioritize the security of energy supply by obtaining LNG under long-term contracts at a significant premium to prices in U.S. and European import markets where LNG imports compete with indigenous production and imported pipeline gas. East Asian markets use pricing formulas that tie the delivered price of LNG to the Japanese Customs Cleared (JCC) price, an average price of crude oil imported to Japan published by the Japanese government every month. These formulas typically consist of a base price and a slope, which is multiplied by the JCC price, such as:

$$\textbf{\textit{CIF LNG Price = Base Price + Slope}} \times \textbf{\textit{JCC}}$$

Actual prices produced from these formulas vary from contract to contract due to different base prices, different slopes, the presence of “S-curves” that temper price changes at high and low oil prices, and different methods for indexing the JCC price marker over preceding months. Each of these variables is negotiable at contract initiation and many contracts have clauses that re-open price negotiation at specific intervals throughout the contract term.

Over the first six months of 2010, the average long-term LNG contract price to Japan ranged from roughly 70-80 percent of the price of oil on an energy equivalent basis averaged over the preceding three months. Figure 9 shows the monthly high price, low price, and unweighted average price of LNG to Japan against the moving average of the JCC oil price over the preceding three months from January 2005 through September 2010. Prices are shown against two axes in nominal US dollars per MMBtu and nominal US dollars per barrel.

Figure 8. **High, Low, and Average CIF LNG Prices to Japan vs. JCC Oil Price, nominal US $/MMBtu and nominal US $/barrel**



Source: Gas Strategies LNG Data Service

In recent years, China and India have negotiated LNG prices with Pacific Rim suppliers that are considerably more favorable than those paid by other Pacific Rim importers. For instance, in May 2010, China paid $3.31 per MMBtu for LNG under its long-term contract with Australia while Japan paid $11.25 on its Australia contracts.[21] This considerable price discount is largely due to leveraging indigenous coal production costs during contract negotiations and to a favorable buyers' market at the time the contract was entered. Although Alaska may have some room to negotiate lower LNG prices with Pacific Rim suppliers under the LNG import scenario, it should generally expect to purchase LNG at prices that are competitive with prices in Japan, South Korea, and Taiwan.

2.5.3.1 Forecasting LNG Prices

In order to forecast LNG prices for this study a "representative" Pacific Rim price formula needs to be obtained. This is a difficult task because the price formula for each LNG contract is negotiated separately and there is a large variance with respect to each contract's base price and slope. Price clauses of in LNG contracts are highly secretive and were not available for this study. For the purpose of estimating LNG pricing formulas, reported LNG prices to South Korea were observed over the past five years and linear regression analysis was used to approximate the base price and slope for an "average" South Korean contract. South Korea was selected for this analysis because it is a large LNG consumer and with growing demand that might be considered "representative" of the greater Pacific Rim market.

Table 12 shows the estimated slopes and intercepts produced from the regression analysis of prices from three of South Korea's four long-term LNG suppliers: Indonesia, Oman, and Qatar. Malaysia, South Korea's fourth long-term supplier, was excluded from this analysis because its prices were consistently lower, possibly representing favorable, grandfathered pricing terms. For each regression, Table 12 also the r-squared (r^2), an indicator of the "goodness of fit" of the slope and intercept to the actual price data, as well the estimated indexation method for each contract. These results were obtained by regressing five years of LNG and JCC price data.

Table 12. Regression Analysis: Estimated Slopes and Intercepts for Long-Term South Korean LNG Contracts (2005-2010)

	Slope	Intercept	r^2	Indexation Method
Indonesia	0.1513	0.6111	0.88	Spot Oil Price
Oman	0.1489	1.2288	0.93	JCC: 4-month lag
Qatar	0.1633	0.1625	0.90	JCC: 6-month moving average
AVERAGE	**0.1545**	**0.6675**		

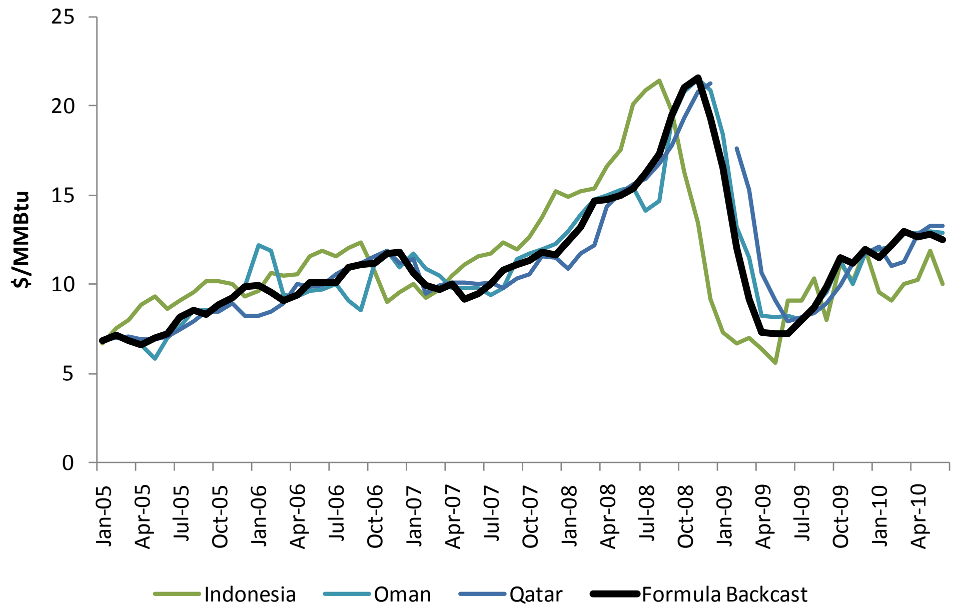
Based on the average slope and intercept from each supplier in Table 12, a "representative" South Korean LNG price formula is estimated as:

$$\textit{CIF LNG Price} = 0.6675 + 0.1545 \times \textit{JCC} \qquad \textit{(Equation 1)}$$

[21] *Gas Strategies LNG Data Service*

In the above equation, the JCC price is input in $ per barrel and the LNG Price output is in $/MMBtu. Thus, at a JCC price of $80 per barrel, the representative Pacific Rim price would be $13.03 per MMBtu. Figure 10 "backcasts" the formula in Equation 1 by inputting historic JCC prices (with a 3 month lag) and compares the resulting formula LNG prices to actual, historic LNG prices to South Korea from Indonesia, Oman, and Qatar.

Figure 9. LNG Price Formula "Backcast" Against Historic South Korean LNG Prices



Source: Backcast data from SAIC, historic data from Gas Strategies

In order to project future LNG prices a forecast of JCC prices would be need to be obtained. To substitute a WTI forecast, the formula would need to be adjusted to account for the differential between the WTI and JCC price. A regression analysis of JCC and WTI data over the past five years shows that the two indices are highly correlated with the relationship being represented by JCC = WTI x 0.98. In other words, the JCC is typically 98 percent of the WTI price. Adjusting the Equation 1 to account for the differential produces the following formula:

$$\textit{CIF LNG Price} = 0.6675 + 0.1515 \times \textit{WTI} \qquad \textit{(Equation 2)}$$

Thus, at a WTI price of $80 per barrel, the LNG price is $12.79 per MMBtu. This price formula will be used to determine the landed CIF LNG price in South Korea for the Alaska LNG export scenario.

For the Alaska LNG import scenario this "representative" price formula would need to be adjusted to account for the shipping cost differential between South Korea and Alaska. The reasoning behind this method is that Alaska, as a small LNG importer, would be a price taker in the Pacific Rim LNG market. Consequently, an LNG supplier (such as Russia) would expect to earn the same netback (CIF LNG price less shipping costs) by selling to Alaska as to South Korea.

Assuming that LNG to the Alaska import terminal will be sourced from Russia's Sakhalin project, the required netback at the export terminal in Sakhalin would be the CIF LNG price in South Korea (given by the price formula) less $0.25 per MMBtu (the estimated cost of shipping baseload volumes of 400 MMcfd from Sakhalin to South Korea annually with LNGC powered by a two-stroke diesel engine with LNG reliquefaction when oil is $80 per barrel). Thus Equation 2 should be adjusted by the shipping cost to produce the following formula:

$$\textbf{FOB LNG Price} = \mathbf{0.4175} + \mathbf{0.1515} \times \mathbf{WTI} \quad \textit{(Equation 3)}$$

Thus, at a WTI price of $80 per barrel, the FOB LNG price in Sakhalin would be $12.54 per MMBtu. To produce the CIF LNG price from Sakhalin to Alaska, shipping costs would need to be added to this FOB price. These shipping cost will vary by the volume of imports (and the number and capacity of the LNGCs needed to deliver that volume), as well as other factors, such as the LNGC's engine-type and the cost of propulsion fuels. Shipping costs are discussed in detail in Sections 2.3 and 2.5.2.

3. PRELIMINARY SITING ASSESSMENT

A preliminary assessment of potential sites for an LNG plant and loading terminal was conducted with the aim of selecting one site at tidewater, and one site in Fairbanks area to be modeled in the subsequent economic analysis. The tidewater region assessment was restricted to Cook Inlet and Kenai Peninsula. After an initial preliminary ranking of sites based on information available on the internet, site visits and interviews with local planners were conducted to adjust the preliminary rankings and identify a single site at tidewater and in Fairbanks area to be used for the economic modeling purposes of this report.

The site selection considerations in this assessment include safety and security, pipeline path for natural gas feedstock delivery, environmental concerns, existence of adequate infrastructure, site suitability with respect to existing Borough/Coastal Master Plans, and general operational and economic feasibility. This site assessment remains at a very high level, with the goal of identifying and comparing major considerations, but not delving into a highly detailed comparison. As such, the selected sites for modeling in this report (i.e., Nikiski and northwest of Fairbanks) should be considered as reasonable sites based on a high-level analysis, but not necessarily the ultimately preferred sites. It should be noted that some potential sites were identified during our interviews that were not included in our preliminary assessment (e.g., the Tyonek dock, Nenana). These sites are mentioned below, but were not further assessed.

Federal regulations considered in this siting assessment are addressed in the following section. Sections 3.2 and 3.3 address potential Southcentral and Fairbanks sites, respectively. Appendix A provides a list of people interviewed for this siting assessment.

3.1 FEDERAL REGULATIONS GOVERNING LNG FACILITIES

This summary of Federal regulatory requirements for LNG facilities and vessels is not exhaustive, but rather indicates the requirements that were considered in this siting assessment. The address below includes primary Federal safety and security regulations that address LNG facilities and vessels, a discussion on safety and security exclusion zones that are designated around LNG facilities and vessels, and closes with brief mention of some additional relevant Federal regulations.

3.1.1 Primary Federal Safety and Security Regulations

This summary of Federal regulatory requirements for LNG facilities and vessels is not exhaustive, but rather indicates the requirements that were considered in this siting assessment. The address below includes primary Federal safety and security regulations that address LNG facilities and vessels, a discussion on safety and security exclusion zones that are designated around LNG facilities and vessels, and closes with brief mention of some additional relevant Federal regulations.

3.1.2 Primary Federal Safety and Security Regulations

Both tidewater and Fairbanks sites will need to meet Federal regulations with respect to safety and security, including, among other things, safety zones surrounding LNG storage. The specific regulations that apply depend on whether a facility is located on a navigable waterway. Safety and security of facilities on navigable waterways are regulated by the U.S. Coast Guard. Facilities that are not on navigable waterways must comply with generally similar (but not exactly the same) U.S. Department of Transportation regulations.

As such, LNG facilities that are not on navigable waters (i.e., some potential Fairbanks sites) are subject to the regulations contained in 49 CFR Part 193 which addresses both safety and security requirements. These DOT regulations incorporate National Fire Protection Association Standard 59A to address safety. In regard to security, LNG facilities not regulated by the Coast Guard that hold over 10,000 lbs of methane are also subject to the Chemical Facility Anti-Terrorism Standards in 6 CFR 27.

In contrast, LNG facilities built on navigable waters must comply with 33 CFR 127, administered by the U.S. Coast Guard. Some, but not all portions of NFPA 59A are incorporated in 33 CFR 127. With respect to security, these facilities must also comply with 33 CFR 105, which calls for a risk assessment and security plan that enacts the security measures necessary to control the risk identified in the assessment.

3.1.2.1 Safety and Security Exclusion Zones

With respect to exclusion or buffer zones that may be designated around onshore storage tanks and LNG carriers, there are no specific distances provided in either DOT or Coast Guard regulations. Rather, the regulations call for assessments to designate these distances. Further, the determination of an exclusion zone distance may differ depending on whether safety or security is the primary interest. Differences in safety and security exclusion zones are due to differing probabilities and consequences of intentional attacks on a facility. An accident scenario with serious consequences that may be deemed a 'less than a one in ten thousand year event' could be reasonably ignored in an accident management program. However, a security threat scenario is controlled by intention not probability, and the serious consequences that are possible might draw the attacker to that specific target.

A common reference with respect to risk analysis and safety distances for a large LNG spill over water is a 2004 report by the Sandia National Laboratories.[22] The Sandia report considers that the size of a breach in LNG containment cause by an intentional act will probably be larger than one

[22] *United States Department of Energy, Sandia National Laboratories, 2004. "Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water," Sandia Report SAND2004-6258. Available at http://fossil.energy.gov/programs/oilgas/storage/lng/sandia_lng_1204.pdf*

caused by an accident. For these reasons it is possible that certain standoff distances (Thermal Exclusion Zones) may be larger for security purposes than if calculated solely on safety considerations.

As a general consideration in the siting considerations of this report, thermal exclusion zones were calculated as the distance at which a maximum heat level of 5kW/meter^2 is projected to occur under a modeled security-based scenario (i.e., an intentional attack). This level of heat will produce second degree burns on a human within 60 seconds unless the person is able to move away from the heat. Use of this threshold to determine an exclusion zone is not a specific regulatory requirement, but rather, a reasonable safety level that could be used in subsequent risk assessments. Lower thresholds by reputable organizations have been suggested, for example: The American Petroleum Institute Recommended Practice (API RP) 521 suggests a permissible exposure to the thermal radiation from flares of 1.6 kW/meter^2 in locations where personnel are continuously exposed, and The Society of Fire Protection Engineers' (SFPE's) handbook of fire protection engineering, second edition, recommends a level of 2.5kW/m2 as a public tolerance limit for exposure to radiant heat. The use of lower thermal thresholds will result in larger thermal exclusion zones. Ultimately, the US Coast Guard or US DOT determines if the thermal exclusion zone proposed for a specific project is acceptable.

3.1.2.2 Other Regulations

New LNG facilities are also required to comply with the Federal Energy Regulatory Commission (FERC) filing requirements contained in 18 CFR parts 153 and 157. In addition planned LNG facilities that are subject to Coast Guard jurisdiction must submit the Letter of Intent[23] to the Captain of the Port no later than the date that the owner or operator files a pre-filing request with the Federal Energy Regulatory Commission (FERC) under 18 CFR parts 153 and 157, but, in all cases, at least 1 year prior to the start of construction. As part of the submission to the Coast Guard, the facility operator must conduct and include a preliminary waterway suitability assessment (WSA) that must in part address: characterization of the LNG and LNGC route; risk assessment for maritime safety and security; risk management strategies; and resource needs for maritime safety, security, and response.

The final regulatory requirement included in this review applies to seismically active areas. Southcentral Alaska is known to be seismically active and as such all LNG terminals constructed after 1993 are required to meet the seismic design requirements as stated in 49 CFR part 41,[24] regardless of whether or not they are located on navigable waterways.

3.2 POTENTIAL TIDEWATER SITES

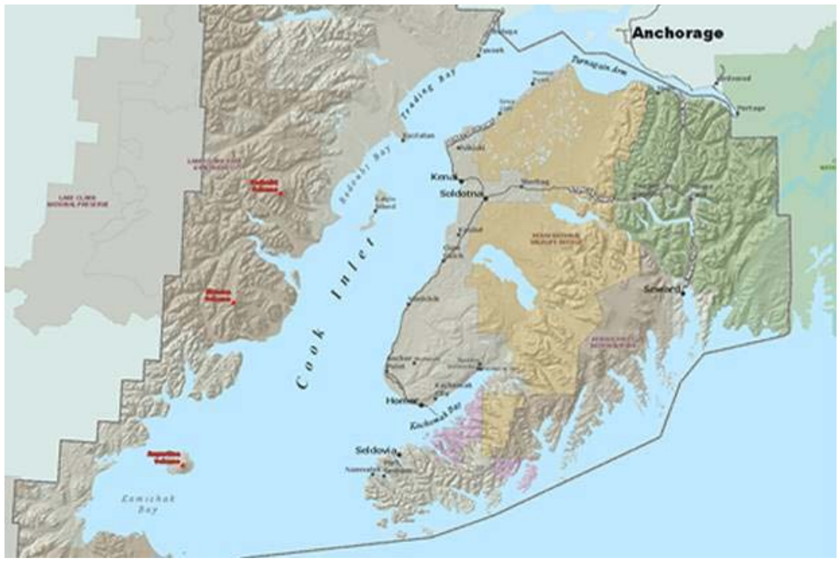
Tidewater sites considered in this assessment are Nikiski, Homer, a general Greenfield port/terminal along the western coast of the Kenai Peninsula, Port MacKenzie, the Port of Anchorage, and Seward. With the exception of Seward, the sites were all located on the Cook Inlet

[23] *For additional information refer to 33 CFR 127.007*

[24] *33CFR 127.1103 requires compliance with the requirements of 49 CFR 41.119 which apply to new building projects for which development of detailed plans and specifications begin after July 14, 1993*

or one of its Arms. Seward is located on Resurrection Bay. Both Cook Inlet and Resurrection Bay are environmentally significant and also support a wide array of recreational activities. Cook Inlet, shown in Figure 11, is approximately 192 miles long and Resurrection Bay is about 20 miles long. Cook Inlet is also home to a specific species of the Beluga Whale family and pending regulations would enact a mandatory management program in many parts of the Inlet and its Arms.

Figure 10. Area Reviewed for Tidewater Sites



The potential sites experience tidal swings range from 10-35 feet and except for Seward, they experience strong tide-driven currents up to 8 knots in speed. While none of the sites are reported to freeze over during the winter, all of them, with the exception of Seward, are impacted by ice flows that originate along the shore or up in the Arms that extend from the Inlet propelled by the current and/or wind. When ships are at berth the ice flows (as shown in Figure 12) can press against them creating enormous strain potentially damaging the ship hulls and the piers to which the ships are berthed.

Figure 11. Ice moves with the current and winds in this picture of Port MacKenzie.

There is significant coastal area that could theoretically be used for the development of an LNG terminal. Realistically, considering the large tidal swings and the need to draw upon existing infrastructure the list of potential sites could be dramatically reduced. The large tidal swings generally require the construction of long piers so that ships at berth will not become grounded during low tides. Seward was unique in this aspect since Resurrection Bay is narrow and deep. Sites with existing deep water berths are Seward, Homer, Nikiski, Port of Anchorage, and Port MacKenzie. Other sites along the Western coast of the Kenai Peninsula from Homer to just south of Anchorage) were considered as one collective potential site. The coast of the Kenai Peninsula below Homer was thought to be too rugged and interspaced with inlets for a terminal to be economically built and operated.

While the West side of the Cook Inlet was outside the scope of this study, discussions arranged by AGDC with John McClellan of the Tyonek Enterprise Development Incorporated highlighted the coal-to-liquid (CTL) project they are planning and the associated potential demand for gas. If successful, the CTL project could consume 200 MMcfd of natural gas to enhance the energy content of jet fuel produced for customers such as Elmendorf Air Force Base. Although not further addressed in this project, it should be noted that this level of demand could represent an anchor consumer for a natural gas pipeline. It should be noted that the current pier at the potential Tyonek development site is inadequate for LNGCs. In addition, navigation of any large vessel on the western side of Cook Inlet would be hampered by the winds, currents, and underwater obstructions, although barge transport of a jet fuel product to Anchorage is probably feasible.

The area reviewed for potential LNG terminal sites falls within three Boroughs, each of which has a Coastal Management Plan. The three plans are maintained by Municipality of Anchorage (for Port of Anchorage), Matanuska-Susitna Borough (Port MacKenzie), and Kenai Peninsula Borough (Homer, Seward, Nikiski and all other sites).

3.2.1 Site Assessment Methodology and Rankings

The existing geography and infrastructure of the Cook Inlet, Knik Arm, and Resurrection Bay was examined to identify potential LNG terminal locations. Based on this initial assessment five existing port sites and one new port site were identified (Nikiski, Homer, a general Greenfield port/terminal along the western coast of the Kenai Peninsula, Port MacKenzie, the Port of Anchorage, and Seward). These sites were compared relative to each other in regard to their, impact on the environment, infrastructure needs, compatibility with existing Borough/Municipal master plans, safety and security, and complexity. Table 13 generally describes the ranking categories.

Table 13. Site Assessment Category Descriptions

Category	Description
Impact on the Environment	• Coastal impacts from added piers, breakwaters, etc. and/or dredging, from the environment in order to create a functioning LNG marine terminal • Additional measures that would be needed to comply with potential Beluga Management Regulations
Infrastructure Needs	This factor considers the changes needed to existing infrastructure (i.e., gas pipeline, railroad, highway, and power lines) to create a functioning LNG marine terminal.
Compatibility with Existing Plans	This factor considers how well the proposed site fits into the existing Master Plans.
Safety and Security Needs	• The availability of adequate separation distances between the proposed site and residential and public service (schools, hospitals, etc) areas[25]. • Cumulative threats to safety that would exist over the entire supply chain from the entrance to the Inlets/Bay.
Complexity	While the total cost of each site cannot be accurately estimated at this time, the complexity of rendering the proposed site suitable was roughly assessed. Generally, higher complexity equates to higher costs. Some of the issued considered in this category were: marine terminal construction needs (including piers, breakwaters if needed), infrastructure changes (gas pipeline, power transmission lines, railroad, and highway), and relocations of any operations.

Each potential terminal location was ranked 1-6 in each category (Table 14), with one indicating the proposed site that conforms best or requires the least effort to comply with the terms of the factor, and six indicating the site that requires the greatest level of effort/expense.

[25] Since the size and exact location/positioning of the ships and landside storage tanks are not known at this time a representative simulation was run using a storage capacity of 150,000 cubic meters of LNG, a postulated 5 square meter hole in the tank with ignition occurring at the source. This produced the following thermal flux radiuses- 10kW/square meter at 565 meters- 9kW/square meter at 590 meters, 5kW/square meter at 760 meters, 2kW/square meter at 1100 meters

Table 14. Preliminary Tidewater Site Rankings

Site	Impact on Environ-ment	Infrastruc-ture Needs	Compatibility with Existing Plans	Safety and Security Needs	Com-plexity	Overall Rank
Nikiski	1	3	1	2	2	1.8
Port MacKenzie	2	1	2	4	1	2
Seward Marine In-dustrial Center	5	4	3	3	4	3.8
Port of Anchorage	3	2	4	6	5	4
Western Kenai Pe-ninsula (greenfield sites)	6	6	6	1	3	4.4
Homer	4	5	5	5	6	5

After consultation with the ADGC, the project team focused its assessment on the terminal locations that were ranked 1-3 in the initial assessment (Nikiski, Port MacKenzie, and Seward). Discussions were held with port/city/terminal management, borough planners, maritime pilots, a tug boat operator, the U.S. Coast Guard, and others regarding these terminal locations (a list of interviewees is provided in Appendix A). The assessment team also visited the existing LNG terminal in Nikiski and dry bulk loading terminal in Port MacKenzie. Based on the information gained during this phase, the rank ordering of the top three facilities was adjusted taking into account the additional information obtained (Table 15).

Table 15. Final Tidewater Site Rankings

Site	Impact on Environ-ment	Infrastruc-ture Needs	Compatibility with Existing Plans	Safety and Security Needs	Com-plexity	Overall Rank
Nikiski	1	1	1	1	2	1.2
Port MacKenzie	2	3	2	4	1	2.4
Port of Anchorage	3	2	6	6	4	4.2
Western Kenai Pe-ninsula (greenfield sites)	5	6	4	3	3	4.2
Seward Marine In-dustrial Center	6	5	3	2	6	4.4
Homer	4	4	5	5	5	4.6

Findings for each of the assessed sites are summarized in the subsections below. As indicated in Table 15, Nikiski was determined to be the preferred tidewater location for an LNG terminal based on the high-level assessment conducted in this study. As such, the economic feasibility modeling of this project will assume costs based on a location at Nikiski. A brief discussion of the considerations for each of the sites shown in Table 15 follows.

3.2.2 Nikiski

Is located on the Cook Inlet and is the site of an existing LNG terminal, the Kenai Plant. The deep water berth is obtained through the use of long piers extending into Cook Inlet (Figure 13). The facility has been in operation since 1969. According to the current terminal operators (ConocoPhillips), the facility has never had a delay in ship operations (berthing, loading/unloading or departure) related to local weather or sea conditions. The only incident at the berth occurred in 1988 when ice pressing on the hull of a LNGC caused it to shift in location to the loading arm. Since that time a tension sensing and adjusting mooring system (dynamic tensioning) has been installed on the pier and no further incidents have occurred.[26]

Both the current LNG terminal operator and the Maritime Pilots that serve the waters of the Cook Inlet stated that Nikiski was originally selected in the 1960's because it is an ideal location for a marine terminal within Cook Inlet.[27] Factors that collectively support this assessment include:

- Currents run parallel to the pier (a preferable orientation for shipping)
- Strong winds during the winter months are significantly blocked by the high bluffs on the shore (Figure 14)
- No dredging has been needed since the current pier was built
- Winter ice flows are less dense than those further in Cook Inlet and the Knik Arm
- Tug boats are not needed or used to bring LNGCs to the berth

The Kenai Plant has a storage capacity of 105,000 cubic meters of LNG and an annual throughput capacity of about 240M cubic feet. The LNGC that is on lease to the operator was built in 1993, has an ice classed hull, and a capacity of 89,000 cubic meters. A second LNGC of the same specifications is currently inactive but could be reactivated. According to the terminal operators, continued operation of current liquefaction facility will require replacement of the compressor turbines. Furthermore, there is sufficient land available adjacent to the Kenai Plant to install an additional LNG train to increase exportation.

Alternatively, if the facility were to be converted to regasification operations (as under an LNG importation scenario), land based vaporizers would need to be installed. Adequate land on the facility and adjacent to it is available for re-gasification. While the facility has received LNG on at least one occasion in the past (from a ship for temporary storage), additional engineering analysis would be needed if offloading LNG becomes a regular operation.

Long-term future operation of the Kenai plant as either an import or export facility may include expansion of the pier and cargo handling system to allow use of larger LNGC. The terminal operator stated that they have developed engineering estimates for expansion to handle 135,000 cubic meter LNGCs (the most common LNGC size today). It should be noted that under a scenario

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[26] During discussions conducted at a meeting between AGDC, Steve O'Malley (SAIC), Mr. Spangler (ConocoPhillips Operations Manager Cook Inlet Area) and Mr. Micciche (Superintendent, Kenai LNG Facility) on January 13, 2011.

[27] In discussions between Captain Pierce, President of the Southwestern Pilots Association, and Steven O'Malley, SAIC, on January 7, 2011.

in which the pier serves as a permanent mooring for an FSRU with ship-to-ship transfers, additional engineering analysis would be needed to determine the need for reinforcement of the pier.

The Kenai Peninsula Coastal District Manager stated that the Borough wants future LNG operations to be sited at the current Nikiski facility. The Kenai Peninsula Borough Coastal Management Plan specifies that:

> *'G-4.2. Use of Existing Facilities. Existing industrial facilities or areas and pipeline routes should be used to meet new requirements for exploration and production support bases, transmission/shipment (including pipelines and transportation systems), and distribution of energy resources'*

In discussions with the Kenai Peninsula Coastal District Manager, Mr. Gary Williams[28], he explained that before a new energy facility could be built within their Coast Management District (includes East and West sides of Cook Inlet and Resurrection Bay) the developers would need to convince the Borough that any existing energy facilities could not be used.

Figure 12. **The Kenai LNG Terminal at Nikiski (middle pier).**

[28] Meeting between David Haugen (ADGC), Steve O'Malley (SAIC), and Gary Williams (Kenai Peninsula Coastal District Manager) on 13 January 2011

Figure 13. Looking North from the LNG Terminal Pier, Bluffs Reduce Winter Winds.

The drawbacks of using Nikiski to site an LNG terminal are:

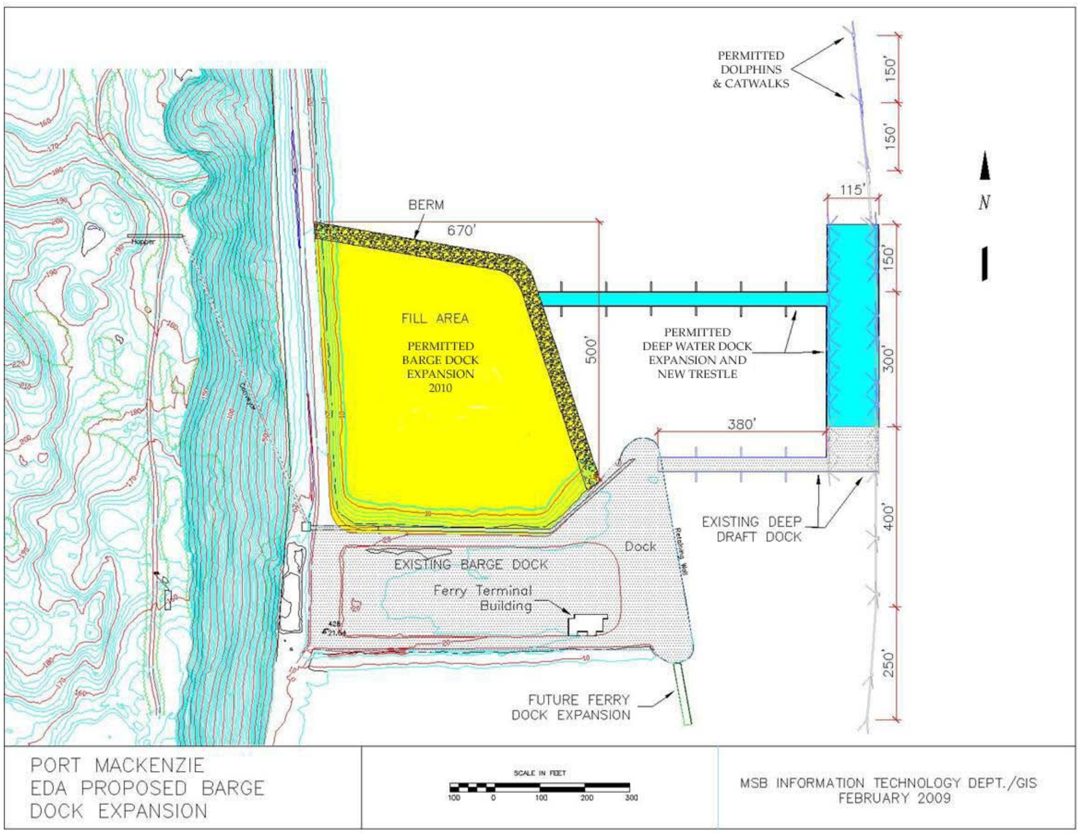
- Site would be within Zone 2 of the Beluga protection area under the proposed regulations
- If this site served as a terminal for a liquefaction plant in Fairbanks, rail delivery from the Interior would require extension of the railroad. Assuming a railroad branching point around Moose Pass, approximately 100 to 120 miles of track would be needed to reach Nikiski.

3.2.3 Port MacKenzie

Port MacKenzie is located at the top of the Cook Inlet in the Knik Arm across from Anchorage, which is the largest population center in the state. This port has an existing deep water berth and currently unfunded plans to expand the pier (Figure 15). The Matanuska-Susitna Borough master plan encourages the development of an LNG and or NGL facility in the port. There is adequate land available for these facilities with associated safety radiuses. However, use of this port for LNG would likely raise safety issues for planned ferry boat operations from the same pier. It is possible that other vessel operations may also be limited for safety reasons when an LNGC is at berth.

Figure 14. Port MacKenzie

The port is located in the Knik Arm where ice forms and moves in dense ice flows driven by wind and current. The area is subject to very high winds and ships entering the Arm are required to maneuver extensively around a shoal and to line up with the berth. LNGCs have large sail areas and are greatly affected by wind. Furthermore, according to a representative of the Southwestern Pilots Association,[29] the tidal currents in the Arm at Port MacKenzie are cyclonic and are not parallel to the berth. As such, much greater force is applied to the ships and piers by the ice and wind.[30] Based on the high winds, ice flow density, strong currents, and nature of the cargo being shipped, periodic disruptions to LNGC operations due to natural conditions is a distinct possibility. While an LNGC may be able to be brought safely to berth with the use of 2 large tugboats,[31] during adverse conditions, this may be considered to be unnecessarily risky. As a result, it is possible that this site may not be able to gain the approval of agencies, particularly



[29] In discussions between the President of the Southwestern Pilots Association, Captain Pierce, and Steven O'Malley of SAIC on January 7, 2011

[30] If the current was parallel to the pier, ice would apply maximum force at the bow or stern of the ship at berth and that strain would also be transferred to the pier. If the current is not parallel to the pier, maximum force of the ice will be applied to a larger section of the hull resulting in greater forces on the vessel.

[31] Captain Pierce anticipated that two 7,000 Hp tugs would be needed, Captain Anderson of Cook Inlet Tug and Barge estimated two 4500-5000 Hp tugs would be needed, and Marc Van Dongen (Port MacKenzie) added that two or more tugs could be used to hold the ships at the berth during periods of high winds.

with recognition that less risky options exist in the region.

Ice-related safety and reliability of Port MacKenzie versus Nikiski is indicated by comparison of ice thickness, percent coverage, and duration. An analysis of NOAA ice data from these two sites (presented in Appendix B) suggests that ice thickness, coverage, and duration are significantly greater at Port MacKenzie than at Nikiski.

Long term viability of deep draft ship operations at Port MacKenzie requires periodic dredging of the entry channels and portions of the Arm. These costs are increasing rapidly; "In the 1980s and 1990s, the average annual excavation at the port was between 250,000 and 500,000 cubic yards of sediment. Starting about a decade ago, the excavation shot up to 800,000 to 1.4 million cubic yards annually."[32] There is a growing shoal that has become a major safety concern for ships entering the Arm. Currently deep draft ships entering the Arm must time their arrivals at the shoals for one hour past low tide. It is estimated that LNGCs would need to wait until 3 hours after low tide to enter the Arm.[33]

A terminal at Port MacKenzie would be within Zone 1 of the Beluga protection zone under the proposed regulations. The exact impact of these regulations cannot be determined at this time since the proposed regulations are being challenged in court, however an active LNG terminal would clearly increase deep draft ship traffic in this area.[34]

The maritime challenges of Port MacKenzie, in conjunction with its location adjacent to a major population center and to a strategic Department of Defense base (Fort Elmendorf) in addition to being in an area of significant environmental concern, make this site appear to be less ideal for an LNG terminal than other sites in Cook Inlet.

3.2.4 Port of Anchorage

The Port of Anchorage, located at the top of the Cook Inlet in the Knik Arm, has existing deep water berths. Under the current expansion plan for port (Figure 16), most of the remaining industrial waterfront will be occupied. Northward expansion of the port is limited by the presence of Elmendorf Air Force Base, while southward expansion is limited by the presence of city of Anchorage. While the Port of Anchorage was ranked third as a potential site in the preliminary rankings shown in Table 15, this site was not considered a viable option due primarily to likely difficulties in purchasing the minimum land required for an LNG facility (e.g., 25 acres).

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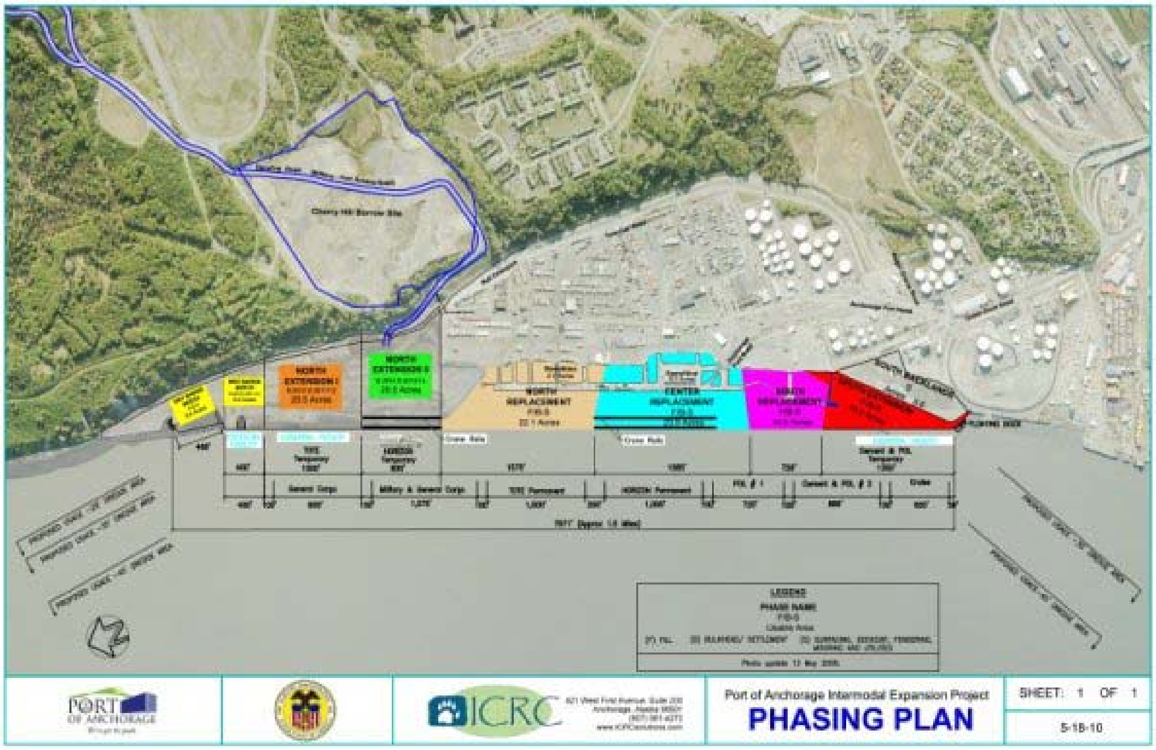
[32] Dredging Today; Cook Inlet Needs Dredging (USA); May 17, 2010
[33] Meeting between Captain Anderson, Cook Inlet Tug and Barge; Steve O'Malley, SAIC; and David Haugen, AGDC, on January 11, 2011.
[34] Current traffic is described in the Cook Inlet Vessel Traffic Study, 2006, http://www.circac.org/documents/pdf/props/CI_VesselTrafficStudy_Final_Mar07.pdf.

Figure 15. Port of Anchorage Expansion Plan



Source: Scott Goldsmith, S. and T. Schwoerer, 2009. Port of Anchorage Intermodal Expansion Program Benefit Cost Analysis of Proposed TIGER Discretionary Grant Funds, Prepared for the Port of Anchorage, Page 7, http://www.iser.uaa.alaska.edu/publications/POA_Benefit_Cost_Analysis_v12sept92009.pdf

- Space for the LNG facility and its safety radiuses would need to come from existing operations
- Unless container operations were disrupted each time a LNGC arrived, another deep water berth would need to be dredged
- Dredging costs in the Arm are increasing dramatically and dredging would need to continue
- The terminal would be within Zone 1 of the Beluga protection zone under the proposed regulations
- Icing, very strong currents and a shoal make navigation in the Arm difficult especially when the LNGC is empty and would be greatly affected by winds (the ship would have a very high freeboard)
- The distance a ship calling on this port would need to travel from sea to Anchorage or MacKenzie is the longest of the potential sites

NOTE: The following three potential LNG terminal locations (i.e., Seward, Homer, and "Other Kenai Peninsula Locations") are located in the Kenai Borough Coastal Management area, as is Nikiski, discussed above. Under the current Kenai Peninsula Coastal Management Plan, existing facilities, such as at Nikiski, are to be used to meet new requirements transmission/shipment and distribution of energy resources to the greatest extent possible. It would have to be proven that the existing LNG terminal is not acceptable before other sites in the Borough could be approved.

3.2.5 Other Kenai Peninsula Locations

There are many sparsely populated areas along the Kenai Peninsula between Homer and Anchorage that could conceivably be used to build a new LNG terminal. However, much of the northern shore of the Kenai Peninsula is part of protected areas (i.e., Kenai National Wildlife Refuge and Chugach National Forest). At locations along the western shore of the Kenai Peninsula, piers 300-500 meters long would need to be constructed. Most of this area is in either Zone 1 or Zone 2 of the proposed Beluga whale protection areas. As with Nikiski, fast currents and drifting ice present navigation hazards and threats to piers. While a rural Greenfield site in these areas provides safety advantages due to the low population density, more infrastructure development would be needed, and there would likely be environmental impacts due to pier construction on a relatively natural coastline.

3.2.6 Seward Industrial Center

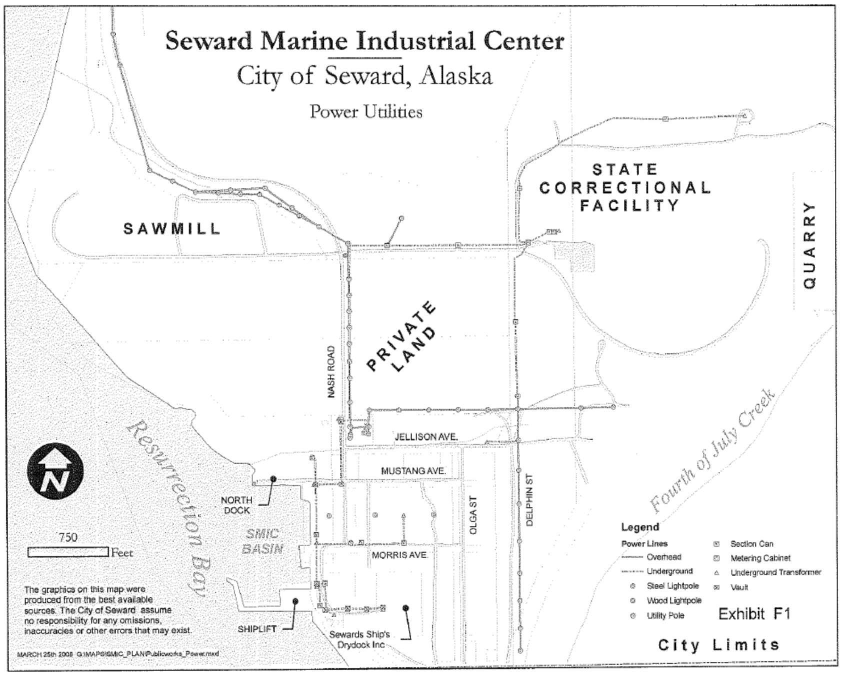
The Seward Marine Industrial Center is located on Resurrection Bay. Resurrection Bay is about 20 miles long, providing a shorter distance for ships to travel from the sea to berth than Cook Inlet. The Bay is ice free, and does not have the ice flow issues as in Cook Inlet. The Bay is also narrow and deep eliminating the need for very long piers for deep water berths. However, tidal reflection is significant in the Bay, which may cause the need for more extensive breakwaters.

Seward is connected by highway to Anchorage, and is the terminus of the Alaska Railroad. Roughly 60 miles of new pipeline would be needed to connect Seward with the existing natural gas system. Alternatively, under a scenario in which the LNG facility is located in Fairbanks area, Seward provides distinct advantages for a marine terminal due to its current access to the Alaska Railroad (the Port of Anchorage is the only other tidewater site considered in this assessment that has current railroad access).

The City of Seward is interested in economic uses of the Marine Industrial Center (Figure 17). The former sawmill site was identified by the Seward City Manager as a specific location that may be available for sale and suitable for an LNG terminal.[35] This location is near a prison, but it is likely that siting could be achieved with a sufficient safety exclusion zone.

[35] *Discussion held between David Haugen (AGDC), Steve O'Malley (SAIC), and Phillip Oats (Seward City Manger) by telephone conference on January 11, 2011.*

Figure 16. Seward Marine Industrial Center



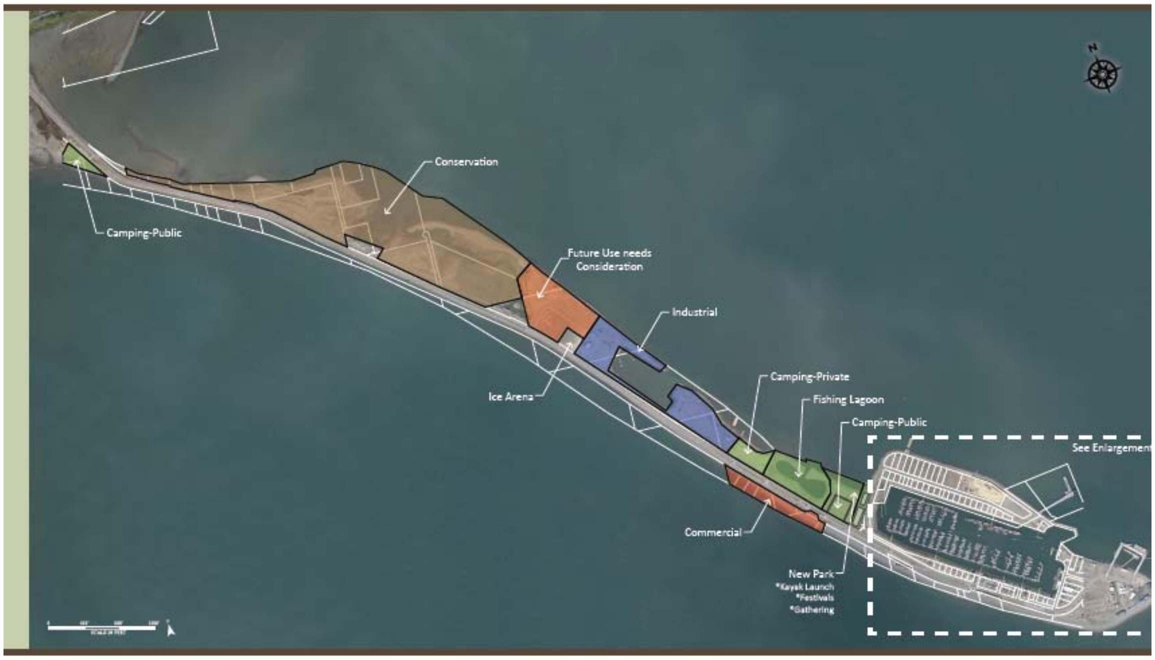
The drawbacks to locating an LNG terminal in Seward Marine Industrial Center are:

- Export or import of natural gas through this port would require significant extension of the current pipeline system, except under a scenario of LNG production elsewhere (i.e., Fairbanks) with rail transport to a marine terminal in Seward.
- More extensive breakwater construction may be needed to prevent swells from the sea and those being reflected back by the end of the Bay.
- The current sawmill pier would need to be enlarged.
- The Kenai Coastal Management Plan states existing facilities should be reuses and this would be a new facility

3.2.7 Homer

Homer is located in the Cook Inlet, about 65 miles by ship from the entrance to the Inlet. Homer has a large natural spit of land projecting into the Inlet (Figure 18). The spit has deep water berths, however, there is little available land for new facilities that require substantial acreage. The population center is located on the mainland, to either side of the spit, with little available nearby land. Hence, a pipeline of several miles would likely need to be constructed to transport LNG product from an LNG plant to the port. Homer is served by a highway that connects it to Anchorage. The waters on the West Side of the spit are not affected by the potential Beluga Whale management regulations. Roughly 55 to 60 miles of new pipeline would be needed to connect Homer to the existing natural gas system (i.e., in Soldotna).

Figure 17. Homer Spit



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Drawbacks of using the Homer Spit to site an LNG facility are:

- It does not fit into the existing master plan for the development of the Spit. The needed safety radiuses would force relocation of existing operations and businesses
- The Kenai Peninsula Borough Coast Management specifies the reuse of existing energy facilities (i.e., as in Nikiski) over development of new sites.
- Requires significant new natural gas pipeline construction.

3.3 POTENTIAL FAIRBANKS SITES

Fairbanks is located in interior Alaska, 360 miles from Cook Inlet. With a population of about 35,000 within the city limits and an additional 63,000 in the greater metropolitan area, Fairbanks is the second largest urban center in the state. The Fairbanks North Star Borough (FNSB) has a Regional Comprehensive Plan that includes goals regarding both land use and economic development.

3.3.1 The FNSB Regional Comprehensive Plan

The most recent Regional Comprehensive Plan for FNSB was adopted in 2005 (FNSB Plan).[36] One of the actions listed in the FNSB Plan as a means to strengthen and expand the existing

[36] *Fairbanks North Star Borough Regional Comprehensive Plan (FNSB Plan), Adopted by the FNSB Borough Assembly September 13, 2005 (Ordinance No. 2005-56) as viewed at http://www.co.fairbanks.ak.us/CommunityPlanning/CPlan%20Adopted%20091305%20with%20pictures.pdf*

economy is to increase the Borough's role in North Slope and state energy development through "support [of] the gas pipeline from North Slope through the FNSB and natural gas value added industries" in addition to "support [of] efforts to develop gas from the Nenana Basin for use in the FNSB".[37]

As seen in Figure 19,[38] the area stretching roughly 5 miles immediately north and west of the Fairbanks city limits is largely designated as perimeter and outskirts areas by the FNSB Planning Commission. Perimeter designations are for regions that are to be primarily for residential use, but industrial development is allowed as a secondary use.[39] Beyond the outskirts area to the west, land use designations are a mix of "high mineral content", "preferred forest", and "open/natural areas". These areas are zoned for general use. Industrial development is not specifically encouraged in these areas.

Further north, significant portions of the land are categorized as having "high mineral content", and land uses that are incompatible with mining are generally discouraged. In a discussion with the FNSB Department of Community Planning, Bernardo Hernandez, Planning Director, suggested consideration of Ft. Knox Mine for future industrial development.[40] It was noted that this area, roughly 15 miles north of Fairbanks, is already cleared, served by roads and a power transmission line, and the mine is nearing the end of its economic production.

The southern edge of Fairbanks is bordered by the Tanana River. The Tanana Flats extend southward from the Tanana River, and are part of the Tanana-Kuskokwim Lowlands. The Flats are classified as a wetland with low scrubs as the dominant type of vegetation.[41] They are a training ground for Ft Wainwright, and are also used by Eielson Air Force Base – the Flats are not connected to the road system.[42] The Tanana Flats are unlikely to be available for industrial development.

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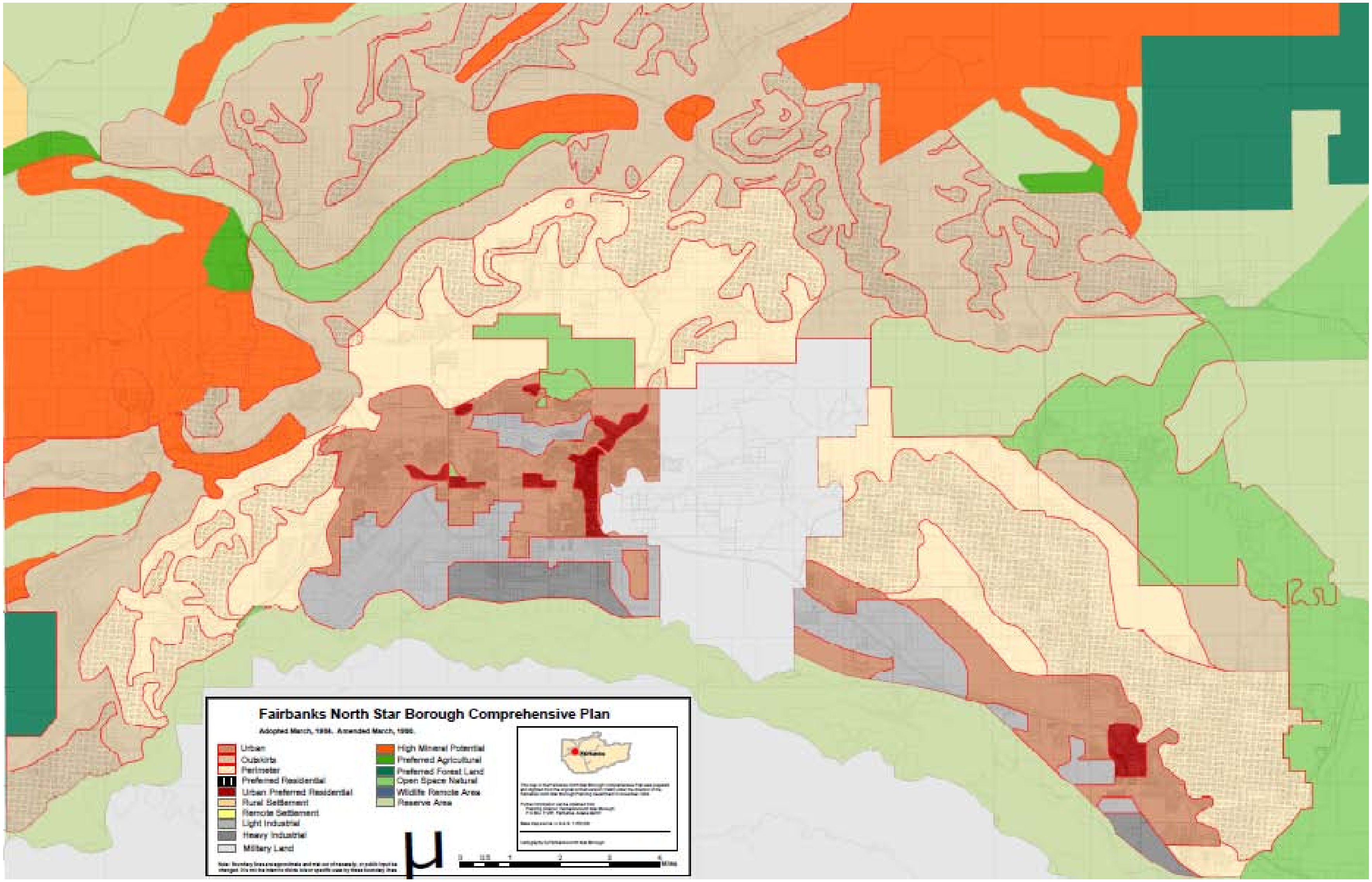
[37] FNSB Plan, page 18.
[38] Fairbanks North Star Borough Comprehensive Plan, FNSB Planning Commission website, as viewed at http://co.fairbanks.ak.us/CommunityPlanning/Comp_Plan_inset.pdf
[39] FNSB Plan, page 17
[40] Meeting held January 13, 2011, with Bernardo Hernandez and Jim Lee, FNSB Planning Department; Paul Mertz, Fairbanks Economic Development Corporation; David Norton, AGDC; and Delma Bratvold, SAIC.
[41] U. S. Department of the Interior Bureau of Land Management, et al., 2002. Tanana Flats Earth Cover Classification, BLM-Alaska Technical Report 45, as viewed at: http://www.blm.gov/pgdata/etc/medialib/blm/ak/aktest/tr.Par.16654.File.dat/TR%2045.pdf
[42] Natural Resources Office, Eielson Air Force Base, Fact Sheet. As viewed at http://www.eielson.af.mil/library/factsheets/factsheet.asp?id=5341

Figure 18. Fairbanks North Star Borough Comprehensive Plan



Source: Fairbanks North Star Borough Planning Commission website, http://co.fairbanks.ak.us/CommunityPlanning/Comp_Plan_inset.pdf

Immediately east of the Fairbanks city limits lies Ft. Wainwright, which extends roughly 4 miles westward. Beyond this US Army base is a flat area transected by the Chena River and tributaries (i.e., Chena Slough, Hopper Creek, Little Chena River, etc.). The FNSB Plan categorizes this land as a perimeter area, for which industrial use is permitted as a secondary use. However, much of the eastern perimeter area is further designated as "preferred residential". Southeast of Ft Wainwright lies the city of North Pole, with urban, light industrial, and heavy industrial areas. The Eielson Air Force Base / Ft. Wainwright Maneuver Area boundary is approximately 2 miles south of North Pole.

In both Fairbanks and North Pole, light industrial and heavy industrial areas are located largely along the Tanana River. The North Pole refineries are located along the river, at the southern tip of the North Pole city limits. The Flint Hills North Pole Refinery, in particular, depends on the Alaska Railroad to transport their products to Southcentral. In both North Pole and Fairbanks, areas designated for industrial use are adjacent to urban areas. Expansion of the industrial areas along the river may encroach on wetlands and raise groundwater contamination concerns.

With respect to future industrial land use, the FNSB Plan calls for sale of public lands (i.e., including a significant portion of the land in perimeter and outskirts areas) after designation and retention of lands for future public use. Furthermore, there is a specific call in the FNSB Plan for industrial land uses in ***both*** urban and non-urban areas, with consideration of traffic flow, safety, and water and wastewater.[43]

3.3.2 Site Preferences and Pipeline Location

From a developer's perspective, key factors for siting an LNG facility are location with respect to the proposed pipeline, a local workforce, and infrastructure development (i.e., railroad, roads, and power lines). While flat land is preferable, lowlands in flood plains offer other concerns.

Primary infrastructure costs for a Greenfield LNG facility include development of the pipeline to deliver gas feedstock to the facility, and connection to the power grid and railway. An important advantage of non-urban areas is that safety exclusion zones are more easily achieved and local "Not-In-My-Backyard" (NIMBY) concerns are reduced.

Under the pipeline scenario of this project, feed gas for a Greenfield LNG liquefaction facility in Fairbanks would be received from the Fairbanks Lateral, an extension of the Alaska Stand-Alone Gas Pipeline originating in North Slope and terminating in Southcentral. The Fairbanks Lateral is to begin at Dunbar, which is located in Yukon-Koyukuk County along the Alaska Railroad, approximately 2 miles west of the FNSB boundary, as shown in Figure 20. It is assumed that the path of the Fairbanks Lateral pipeline would be along the railroad right-of-way, extending about 35 miles from Dunbar to the northwest corner of Fairbanks.

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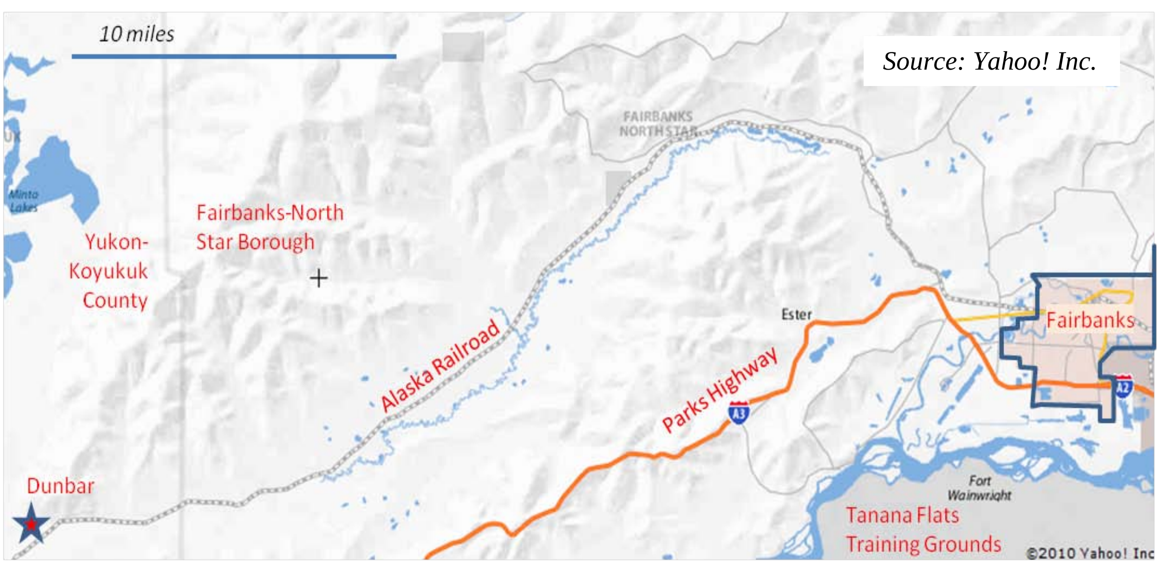
[43] *FNSB Plan, page 12.*

3.3.3 General Areas Considered for a Greenfield LNG Facility

To export product from a liquefaction facility in the Fairbanks area, LNG is to be transported by rail to a marine terminal for temporary storage prior to ship transfer for transport to a Pacific Rim Market. Hence, the northwest corner of the Fairbanks area provides a logical area for a Greenfield LNG facility to minimize pipeline and railway distance. Much of the land in this area is zoned for general use. Other zonings in this area are primarily for rural residential and residential agricultural use.[44] The railway exits the northwest corner of Fairbanks, running beside Sheep Creek Road for nearly 5 miles. It then turns west to run roughly parallel and between Goldstream Creek and Murphy Dome Road for about 8 miles, after which it departs from Murphy Dome Road and continues running parallel to Goldstream Creek for the remainder of the distance to Dunbar. Goldstream Creek runs through a valley that is roughly a quarter mile wide. There is very little development along the railway/ Goldstream Creek west of the intersection of Murphy Dome Road and Cache Creek Road (approximately 15 miles from the edge of Fairbanks city limits by road). Hills surrounding the Goldstream Creek valley typically peak around 500 to 700 feet above the creek bed. Portions of the valley and surrounding slopes may be suitable for an LNG facility.

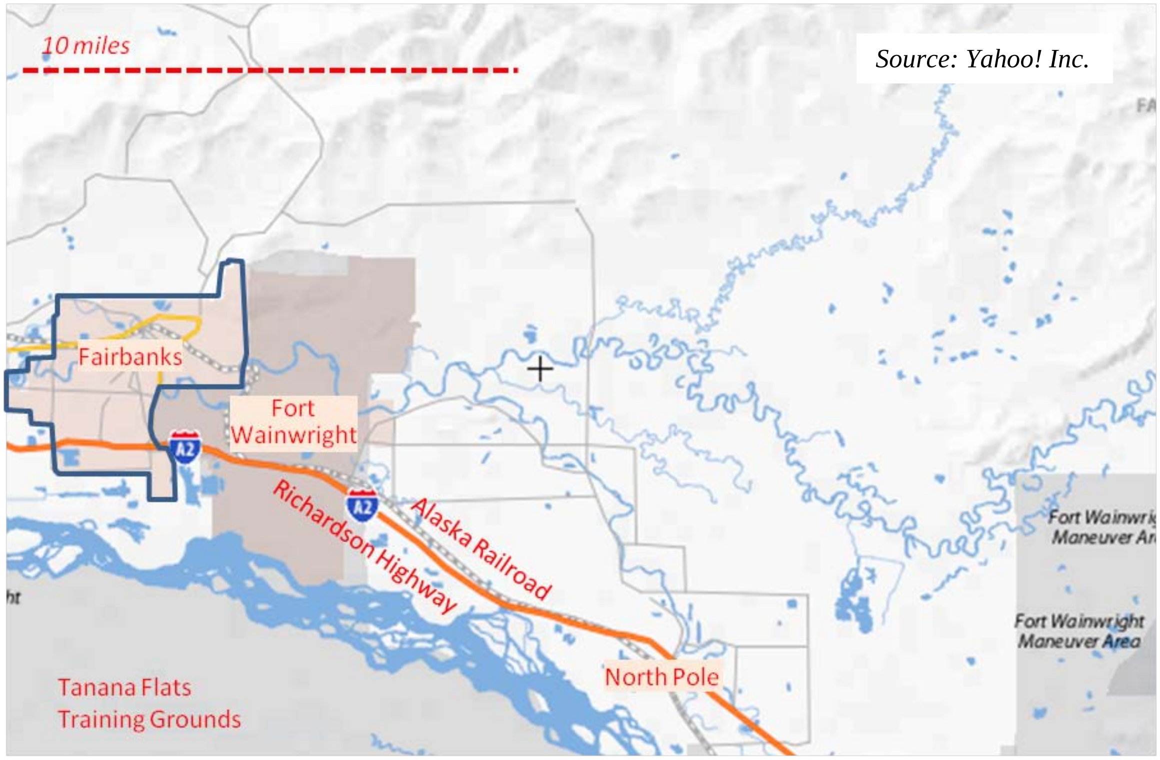
Alternative potential sites for a Greenfield LNG facility along the railway exist southeast of Fairbanks, in areas that are in or adjacent to planned industrial areas -- although much of this area is already well-developed. As shown in Figure 21, the railway exits the southeast corner of Fairbanks and Ft. Wainwright running parallel to the Tanana River and the Richardson Highway (A2). This area is quite flat, with some open areas. A levee protects this lowland from Tanana River floods. Other regions surrounding Fairbanks appear to be less favorable for Greenfield LNG development.

Figure 19. Western Side of Fairbanks



[44] *Fairbanks North Star Borough's Geographical Information System (GIS) as entered through http://gis.co.fairbanks.ak.us/*

Figure 20. **Eastern Side of Fairbanks**



3.3.4 The Railroad

The railroad between Fairbanks and Cook Inlet is operated by the Alaska Railroad Corporation (ARRC), which is owned by the state of Alaska. This railroad terminates at Eielson Air Force Base, approximately 25 miles southeast of Fairbanks. Freight traffic on the rail line includes petroleum products from the North Pole refineries. Under the Northern Rail Extension Project, the Alaska Railroad is currently being extended to Delta Junction for both passenger and freight transport.

Current rolling stock operating on the Alaska Railroad includes 51 locomotives, two power cab cars, 48 passenger cars, 457 fuel tankers, 350 flat cars, 460 hoppers, 31 air dumps and 14 box cars.[45] An LNG facility in Fairbanks area would add several hundred freight cars (specialized for LNG transport) for operation on this railroad. It is estimated that under the LNG facility scenarios modeled in this study, the length of the LNG freight trains would be in excess of a mile long, with daily passage of one or two trains in each direction.

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[45] *Northern Extension Rail Project, Railway-Technology.com -- The Website for the Rail Industry, as viewed at http://www.railway-technology.com/projects/northern-rail/*

The FNSB Plan calls for the encouragement of movement of the Alaska Railroad yard to outside the Fairbanks urban core. [46] These objectives suggest that FNSB planners may have interest in avoiding passage of additional rail traffic through Fairbanks, which could be achieved by siting the LNG facility in the northwest perimeter area.

3.3.5 Siting Comments from Local Planners

Two meetings were held on January 13, 2011 with FNSB planners regarding possible locations for an LNG facility with cogeneration and associated power sales to the grid. The first meeting was attended by Bernardo Hernandez and Jim Lee of the FNSB Department of Community Planning, Paul Mertz of the Fairbanks Economic Development Corporation, David Norton of AGDC, and Delma Bratvold of SAIC. A second meeting was conducted with Mike Wright and Kathryn Lamal of the Golden Valley Electric Association, and David Norton and Delma Bratvold. Comments from the discussions during these meetings are summarized below.

Concerns were expressed regarding expansion of the current FNSB industrial areas, which are located adjacent to the Tanana River. It is not clear that an area of sufficient size (i.e., in the range of 25 acres) could be made available in these areas. Furthermore, these areas are lowlands that have higher chances of water contamination. It was noted that there are already drinking water restrictions in a residential neighborhood adjacent to the North Pole industrial area a result of water contamination from industrial activity. A new, large industrial facility within FNSB would be expected to be responsible for developing an acceptable water source, on-site wastewater disposal or septic system, and stormwater management plan.

It was also noted that residents of the perimeter and outskirts areas are often quite sensitive to nearby development. Further, residents in the Ester area have complained about noise from a nearby mine, and may quickly mobilize against plans for a large industrial facility in this area. There seemed to be consensus among those present that locating a facility outside the greater Fairbanks area may be preferable for a variety of reasons, including prevention of further exacerbation of air quality non-compliance within Fairbanks.

The long-term plan of moving the Alaska Railroad yard from downtown Fairbanks was also addressed, although none of the previously considered alternative main-line routes and yard locations are beyond perimeter and outskirts areas. The long-term appeal of mile-long LNG trains passing at least twice daily through Fairbanks was questioned.

It was noted that the Ft Knox Mine is nearing the end of economic production, is cleared land, has road access, and is connected to the power grid. Ft Knox is approximately 15 miles northeast of Fairbanks by road. The railroad would need to be extended by 15 to 20 miles to reach Ft Knox Mine, depending on the preferred branch point.

The power grid in the Fairbanks area, including the power line to Ft Knox, is able to handle up to 200 MW new generation capacity without significant upgrades. This is nearly twice the cogene-

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[46] *FNSB Plan, page 12.*

ration power that is estimated to be able to be produced from the largest LNG facility considered in this project. It was noted that with respect to power and rail, both Nenana and Healy are also well-positioned for a large industrial facility. While Nenana is arguably within commuting distance to Fairbanks (approximately 50 miles), it is not clear that it would draw a Fairbanks workforce.

The FNSB Department of Community Planning is in the final stages of completing a GIS-based Land Capabilities Analysis that will allow prospective developers easy access to available data on floodplains, elevation, soil conditions, permafrost depth, and other factors. If Fairbanks area is considered in subsequent siting assessments, this tool may facilitate identification of specific sites.

3.3.6 Conclusions and Recommendations for Fairbanks Siting

In this high-level siting assessment, we have considered general areas surrounding Fairbanks. Table 16 provides a comparison of the general sites considered.

Table 16. Comparison of General Locations for a Greenfield LNG Facility in the Fairbanks Area

	Pipeline Distance & Tariff	Rail	Transmission	Community	Environmental
NW Fairbanks	20 miles lowest tariff	nearby	10 miles	General Use, very low density residential	Assume terracing
SE Fairbanks	40 miles approximately $0.62/MMBtu more than NW Fairbanks	nearby	nearby	general use, residential, train passage through Fairbanks	Lowland, water concerns
Ft Knox Mine (NE Fairbanks)	45 miles approximately $0.77/MMbtu more than NW Fairbanks	20 miles	nearby	Currently industrial use	Minimal

Siting a Greenfield LNG facility northwest of Fairbanks, near the railroad, has the advantages of reducing the length of the pipeline for gas delivery by about 20 miles. There would be a similar reduction in the distance the LNG product would be transported by rail. Further, a location northwest of the city limits would improve safety and security of transport by eliminating the need for product transport through Fairbanks, in addition to avoiding possible local concerns regarding lengthy wait times at rail crossings. The estimated increase in the pipeline tariff with locating an LNG facility southeast of Fairbanks or at Ft Knox mine is significant. The tariff increases for a Ft Knox location may outweigh the reduced environmental concerns of using a brownfield site.

For the purposes of the high-level economic analysis conducted in this study, a Fairbanks location is 20 miles east of Dunbar along the railroad will be assumed.

4. ECONOMIC MODELING

4.1 MODEL INPUT AND ASSUMPTIONS

All monetary inputs and outputs of the economic model are in 2011$. Capital cost and general operations cost estimates used in this model were developed for the Gulf Coast and then adjusted by multipliers to account of Alaska-specific costs. The multipliers applied were 1.25 and 1.56 for tidewater and Fairbanks facilities, respectively, per communication with AGDC.

Table 17 displays economic modeling assumptions and input variables. The values shown for input variables are those used for the purposes of the results shown in this report, however, these variables can be easily edited on the "Input" sheet of the model to allow AGDC to examine the modeled project scenarios with different economic assumptions.

Table 17. Economic Model Assumptions and Variables (2011$)

<table>
<tr><th>Model Assumptions</th><th>Input Variables Default Values
(may be changed on the "Input" sheet)</th></tr>
<tr><td>Project Life: 20 years
Loan Period: 20 years (not including construction loan)
Federal Tax Rate: 35%
State Tax Rate: 9.4%
Kenai Ad Valorem Tax Rate: 1.14%
Fairbanks Ad Valorem Tax Rate: 1.48%
Carbon Cost ($/ton CO2 equivalent):
$30 in 2020, $60 in 2030
Non-Fuel Operations Escalation Rate: 3.0%
Capital Escalation Rate: 3.0%
LNG Shipping Costs: $0.73 to $0.82/ MMBtu (varies with scenario carrier assumptions)
Export Facility Construction Period: 3 years at Tidewater, 4 years at Fairbanks
Import Facility Construction Period: 2 years</td><td>Debt to equity: 70%
Cost of Equity: 12%
Cost of Debt: 6.5%
WTI Crude Oil ($/bbl): $80 (converted to other fuels as described below)
Petroleum Escalation Rate: 3.0%
First Production Year: 2016 or 2019
Capital Expenses (see below)
Operational Expenses (see below)
Pipeline Tariff, $/MMBtu:
<table>
<tr><th>LNG Offtake</th><th>Nikiski</th><th>Fairbanks</th></tr>
<tr><td>250 MMcfd</td><td>$7.90</td><td>$6.25</td></tr>
<tr><td>500 MMcfd</td><td>$6.76</td><td>$5.15</td></tr>
<tr><td>750 MMcfd</td><td>$6.03</td><td>$4.74</td></tr>
</table></td></tr>
</table>

Levelized pipeline tariffs were provided by AGDC. It should be noted that the base tariffs used in the analysis for Fairbanks has the simplistic modeling assumption that the pipeline will either stop there or go on to Anchorage with much smaller volume after the LNG gas is taken off. This may not be a realistic assumption, as it may increase the cost of gas to Southcentral consumers to the point where it would no longer be economically feasible.

The economic modeling conducted as part of this analysis assumes that all projects have separate loans for construction and operations phases. Construction loan principle is equally distributed among the construction years. Interest on the project loan is capitalized during construction.

4.1.1 LNG and Petroleum Prices

CIF LNG prices were estimated for the Export Scenario using a "representative" South Korean LNG price formula, which was obtained by performing a regression analysis on South Korea's long-term CIF LNG prices. FOB LNG prices in Sakhalin, Russia were estimated for the Import Scenario by subtracting estimated shipping costs from Sakhalin to South Korea from the South Korean CIF LNG price. (See Section 2.5.3 for details on price formula methodology). CIF and FOB LNG prices are calculated by the following formulas where WTI is input in $ per barrel and LNG prices are output in $ per MMBtu:

$$\text{CIF LNG Price}_{\text{(S. Korea)}} = 0.6675 + 0.1515 \times \text{WTI}$$

$$\text{FOB LNG Price}_{\text{(Russia)}} = 0.4175 + 0.1515 \times \text{WTI}$$

In the export scenarios, it is assumed that all LNG sales are at the CIF price. Shipping based on the destination market are subtracted to calculate revenue. In the import scenarios, the LNG FOB price is assumed. Shipping costs are added based on the supply origin to calculate LNG costs as a separate operating expense. In both import and export scenarios, LNG price and shipping costs are inflated as appropriate.

4.1.2 LNG Capital Expenses

The capital cost estimates are based on industry published values for similar projects, application of time, location and complexity index factors, and R. W. Beck's in-house data and knowledge. These high level industry data on liquefaction plant costs include storage and loading jetty.[47] Cost data was adjusted for time and complexity and applied to the three identified plant sizes to develop the cost estimates for this study in terms of Gulf Coast costs. Breakouts of liquefaction, storage, and jetty/loading costs were estimated based on average proportions of total project costs associated with these components, i.e., 73%, 15%, and 12%, respectively. Breakout costs were subsequently adjusted for Alaskan costs by the multipliers of 1.25 and 1.56 for tidewater and Fairbanks locations, respectively. Tidewater multipliers were applied to jetty/loading costs under both tidewater and Fairbanks scenarios. Costs, shown in Table 18, are the final adjusted capital cost estimates, including all direct and indirect costs for the liquefaction facilities (i.e., permitting, engineering, project management, procurement, construction and startup). Financing costs are added in the economic modeling.

[47] *A Greenfield jetty is assumed although it should be noted that refurbishment of the existing jetty at Nikiski is likely to be significantly less costly than new jetty construction.*

Table 18. Estimated Capital Costs of LNG Export Scenarios (million 2011$'s)

	Tidewater Greenfield			Tidewater Brownfield	Fairbanks Greenfield		
Throughput (MMcfd)	250	500	750	240	250	500	750
Liquefaction	1,264	1,668	1,961	519	1,577	2,081	2,448
Storage	260	343	403		324	428	503
Jetty/ Loading	208	274	322		208	274	322
Rail	NA	NA	NA	NA	775	1,338	1,889
Total	1,731	2,284	2,687	519	2,884	4,121	5,162

NA = Not applicable

The Fairbanks location is assumed to have facilities essentially identical to the Tidewater location with the liquefaction facility at Fairbanks and the storage and jetty located at Seward, thereby avoiding the costs of roughly 125 miles of new railroad construction needed if the marine terminal is located in Nikiski. The Fairbanks capital costs include additional rail-related costs to transport LNG from Fairbanks to tidewater. Rail costs include cryogenic rail cars, new locomotives, additional sidings to accommodate the two way rail traffic, and additional "buffer" storage at the Fairbanks liquefaction facility. The additional storage at Fairbanks is included in the "Rail" line capital costs of Table 18, along with LNG rail loading and offloading technology development. LNG has never been transported by rail in the large quantities modeled in this study, hence none of the current rail transfer technologies are designed to transfer these quantities of a cryogenic liquid to rail cars within a 24-hour period. As a result, there is significantly greater uncertainty in rail capital costs due to the greater uncertainties in new technology development.

The accuracy of total project cost estimates developed for this analysis are in the accuracy range of AACE Recommended Practice No. 18R 97, Estimate Class 5 (Concept Screening – level of project definition is 2% or less), for which expected accuracy low side is -20% to -50%, and high side is -30 to +100%, based on current market and economic conditions. These estimates assume that current costs will prevail regardless of any near or mid-term surplus liquefaction capacity on the global scale. The lower specific costs reported in the media ($'s per MMTPA) realized over the past 10 years are primarily due to economies of scale resulting from larger trains. The relatively small size of the facilities studied and high US/Alaska labor costs will tend to counteract cost savings that may occur due to reduced profit margins for EPC contractors during low activity periods. Construction labor costs are estimated to be approximately 40 to 50% of the cost of a new liquefaction facility. More details on capital costs estimates are provided in Appendix C.

4.1.3 Liquefaction Facility Production Volumes

Three cases were selected for the liquefaction scenarios: inlet processing capacity of 250 MMcfd, 500 MMcfd, and 750 MMcfd. These inlet volumes where combined with the assumed gas analysis after treating as provided by AGDC to yield annual LNG production. The assumed gas analysis' as provided by AGDC are shown in Table 19.

Table 19. Mole % of Inlet Gas

	Tidewater Location			Fairbanks Location		
	250 MMcfd	500 MMcfd	750 MMcfd	250 MMcfd	500 MMcfd	750 MMcfd
CO_2	1.52	1.52	1.52	1.52	1.53	1.53
N2	0.70	0.70	0.70	0.70	0.7	0.70
C1	90.88	91.29	91.35	91.28	91.63	91.72
C2	5.96	5.81	5.80	5.18	5.50	5.60
C3	0.94	0.67	0.63	1.32	0.64	0.45
IC4	0.00	0.00	0.00	0.00	0.00	0.00
nC4	0.00	0.00	0.00	0.00	0.00	0.00
C5+	0.00	0.00	0.00	0.00	0.00	0.00
Total	100.00	100.00	100.00	100.00	100.00	100.00

Because of the extreme low temperatures of LNG, all CO_2 must be removed in the treating section of the liquefaction plant. After accounting for this volume shrinkage, the inlet gas volumes were then reduced for estimated fuel consumption. Fuel consumption was assumed to be 9% of the treated BTU's entering the plant. This is based on approximately 6% of the Btu's being consumed in the gas turbines driving the refrigeration compressors and turbine driven power generators. We estimated approximately 72,500, 145,000 and 217,500 hp of refrigeration compression for the three volume scenarios. In addition, we estimated approximately 8.3, 16.5 and 24.8 Megawatts (MW) of power consumption for the three volume scenarios. An additional 3% of the inlet BTU's was assumed to be consumed for dehydration, treating, process heating, pumping and other plant needs. The plants were assumed to run 350 days per year to estimate annual production.

Based on the above information and assumptions, annual production of LNG in Metric Tonnes per year (MMTPA) was calculated. The results are summarized in Table 20 below, with slight differences among locations due to the assumed differences in inlet gas composition.

Table 20. Liquefaction Volumes

	Tidewater Location			Fairbanks Location		
Raw Inlet, MMcfd	250	500	750	250	500	750
MMBTU/ day	261,536	520,404	780,171	261,484	518,994	776,907
Fuel	23,538	46,836	70,215	23,534	46,709	69,922
LNG, MMBTU/day	237,997	473,568	709,956	237,951	472,284	706,985
LNG, Metric tonnes/day	4,481	8,962	13,443	4,481	8,961	13,441
LNG, MMTPA	1.57	3.14	4.70	1.57	3.14	4.70

For the offshore import scenario (with an FSRU), an engineering analysis would likely need to be conducted to determine if the pier needs reinforcements to accommodate ship-to-ship transfers between the carrier transporting LNG and the FSRU. This analysis was beyond the scope of this study, but a placeholder of twice the estimated costs of jetty expansion under the onshore Brownfield scenario was used to model jetty expansion costs for the offshore regasification scenario. Further, it was assumed that either the ConocoPhillips pier or the Agrium pier would be purchased at a depreciated cost for permanently docking an FSRU.

4.1.4 Rail Capital Expenses

For scenarios with the liquefaction plant located in Fairbanks, LNG marine terminal locations were considered at Nikiski and at Seward. Capital costs for Nikiski could benefit from reuse of the existing Nikiski jetty but would require building a new rail link approximately 125 miles long. A Seward location would eliminate the new rail link but would require capital for a Greenfield jetty. A high-level comparison of capital costs for a marine terminal in Seward versus construction of a rail link to Nikiski indicates that Seward may have lower costs. However, caution should be used in the conclusions from this assessment due to the highly variable costs of jetty and breakwater construction – full analysis of the many factors that affect jetty and breakwaters costs was beyond the scope of this study. Also not considered in this analysis is the potential public concern regarding LNG trains that may be in excess of a mile in length passing through Anchorage (under both Nikiski and Seward marine terminal scenarios).

Although large cryogenic rail cars as modeled in the Fairbanks estimates have been built and are available, we are not aware of any project that has transported this large volume of LNG over rail. One rail equipment supplier indicated they had only built approximately 100 cryogenic rail cars over the past 12 years. The LNG production volumes for the 250 MMcfd case would require approximately 400 cars to assemble the four train sets needed for continuous LNG transport to the terminal under assumptions, including an estimated 10% heel volume.[48]

4.1.5 Rail Operational Costs

Operational costs for rail include diesel fuel to power the locomotives. Alaska diesel prices were estimated for the Fairbanks Export Scenarios (rail fuel costs) using a price estimation formula that ties the Alaska diesel price (in $ per gallon) to the WTI oil price (in $ per barrel). This formula was obtained by regressing five years of No. 2 diesel prices for industrial consumers in Alaska against spot WTI oil prices and is given by the following equation:

$$\text{No. 2 Diesel}_{\text{(Alaska)}} = 0.8336 + 0.0228 \times \text{WTI}$$

LNG vapor losses during the loading and unloading of hundreds of railcars may be significant. Making and breaking connections will necessarily result in some LNG vaporization and loss from each activity. We are not aware of a loading/unloading scheme for quickly handling hundreds of cryogenic liquid-filled rail cars, but have projected losses of 1.5%, which are accounted for in the

[48] LNG storage tanks, whether stationary or in trucks, ships, or railcars, typically retain a “heel” volume of LNG to allow permanent maintenance of cryogenic conditions. This prevents repeated losses associated with the initial cool-down of the tanks, and avoids significant operational issues resulting from frequent warm-ups and cool-downs.

economic modeling of this study. In addition to the value of the loss gas, the primary constituent of LNG, methane, is a potent greenhouse gas – a factor that is not considered in this study.

Finally, it should also be noted that in discussions with the Alaska Railroad (Roy Thomas, Director, Engineering Services, on January 11, 2011), it was stated that they would need to obtain further information to determine if in-line forces are a concern for the train lengths anticipated under the 750 MMcfd scenario. This issue may require separating the train sets into multiple units with more locomotives and longer transit times than estimated.

4.1.6 Brownfield Import and Export Capital Expenses

Capital costs for Brownfield LNG export and import facilities were calculated as 30% of Greenfield capital costs of similar facilities. Both of the Brownfield estimates are based on high-level analyses in which the resale value of the current Kenai LNG plant is estimated in addition to costs of refurbishment (for export scenarios) and renovation/conversion (for import scenarios). For the Brownfield LNG export facility, it is assumed that refurbishment of the Kenai LNG Plant to serve an additional 20 years would require roughly 20% to 35% of the capital that would be needed for a Greenfield LNG facility of similar size. This estimate assumes use of the current storage tanks and dock, with use of the 89,000 cu m LNG carriers that have previously served this facility.

For the Brownfield import scenario, it is assumed that renovation of the Kenai LNG Plant to serve as a regasification facility would require roughly 25% to 40% of the capital that would be needed for a Greenfield regasification facility of similar size. The Brownfield cost estimate assumes use of the current storage tanks and the 89,000 cu m LNG carriers that have previously served this facility. Fuel use during regasification is estimated to be 1.5% of throughput, and is not specifically included in the high-level cost estimates used in this economic analysis.

4.1.7 Cogeneration Capital Expenses

The hot exhaust gas from gas turbines driving the compressors and the power generators in each scenario present a cogeneration opportunity by converting the energy in the exhaust gas to steam and generate electricity for export from the facilities. For the purposes of this analysis, cogeneration costs are calculated as the incremental capital and operational cost differences between a base case without cogeneration, and a second case with cogeneration. Recognizing that the owner/operator of processing facilities is typically different from the owner/operator of cogeneration facilities, the economics of these components are kept separate. Cogeneration estimates do not include a price for waste heat (i.e., fuel), and thus are likely an underestimate.

For the 250 MMcfd case at both liquefaction locations, a base case (without cogeneration) includes the installation of three gas turbines to drive the compressors and a single smaller gas turbine to drive a generator to support the power needs of the facility. The installations were assumed to double and triple the number of gas turbines for the 500 MMcfd and 750 MMcfd cases, respectively.

To capture and utilize the energy in the gas turbine exhaust it is assumed that a dedicated heat recovery steam generator (HRSG) will be added to each of the gas turbines of the base case. For the 250 MMcfd case, it is also assumed that the steam from the HRSGs associated with the larger gas turbines driving the compressors will be gathered and supplied to a single steam turbine, rated at approximately 27 MW, in a 3x3x1 configuration, including a condenser, cooling tower, and other balance of plant (BOP) equipment. We have assumed that the steam from the HRSG associated with the gas turbine driving the power generator will be supplied to a separate steam turbine, rated at approximately 3 MW, in a 1x1x1 configuration, including a condenser, cooling tower, and other BOP equipment. This yields a total cogeneration capacity of 30 MW for the 250 MMcfd case. The installations are assumed to double and triple the number of HRSGs, steam turbines, and BOP equipment for the 500 MMcfd and 750 MMcfd cases, respectively. Capacity availability is estimated at approximately 93%.

The local power companies were contacted to determine the ability of current power distribution system to accommodate cogeneration capacities of 30 to 90 MW. Homer Electric Association (serving Nikiski) stated that this capacity would likely require significant grid upgrades. Golden Valley Electric Association (serving Fairbanks) stated that their current infrastructure can accommodate up to 200 MW in additional generating capacity.[49]

4.1.8 Operational Expenses

Operational expenses include facility maintenance and operations (i.e., labor and expendables), shipping costs, municipal property and sales tax, and carbon costs. For the Fairbanks scenario, operational expenses also include diesel fuel for rail trains. Each of these is described below.

4.1.8.1 LNG Facility Operational Costs

Operating costs were estimated based on industry experience and R. W. Beck's internal data primarily based on gas throughput. For the LNG export scenarios, operational costs in 2011$ for maintenance, minor repairs, other expendables, and labor are estimated as $68, $77, and $86 million per year for the 250, 500 and 750 MMcfd LNG facilities in Southcentral. The Brownfield LNG facility is estimated to have operational expenses that are similar to the 250 MMcfd Greenfield facility, scaled down by the ratio of 240/250.

Operating expenses under the Fairbanks scenarios are estimated to be $175, $237, and $298 million per year. The greater operational costs in Fairbanks are due to both high general costs in Fairbanks and additional expenses associated with rail transport to tidewater, not including rail diesel fuel (addressed separately, below). Non-fuel operational costs are escalated by 3% per year in the economic model

Under the Fairbanks scenarios, each train roundtrip is estimated to consume 38,000 gallons of diesel, which is accounted for in the economic model based on $80/barrel West Texas Intermediate (WTI) and the historical relationship of WTI to Alaskan diesel price. Fuel operational costs are escalated by 3.5% per year in the economic model.

[49] *E-mail from Mike Wright, Vice President Transmission & Distribution, Golden Valley Electric Association, dated 1/14/11.*

Import scenario operational costs are based on maintenance costs of 1% per year of capital expenses for new equipment and 2% per year of capital expenses for old equipment, plus labor estimate of 40 full-time skilled workers at $100K per year including benefits. For the LNG import scenarios, operational costs in 2011$ are estimated to be $5 million per year for the offshore (FSRU) option, and $9 million per year for the two onshore options. As with the export scenario, operational expenses are escalated by 3% yearly in the economic model.

4.1.8.2 Shipping Costs

Shipping costs for LNG exports are estimated for transport from Nikiski to South Korea assuming the use of newly constructed LNGCs powered by two-stroke diesel engines and LNG reliquefaction. The number and capacity of these LNGCs was optimized to minimize shipping costs given the required delivery volumes and the distance to the importing market. Shipping 250 MMcfd of baseload LNG to South Korea would be optimized by using one Q-max (260,000-270,000 cu m) LNGC. Shipping 500 MMcfd would require two Q-max LNGCs and shipping 750 MMcfd would require three (See Section 2.5.2 for more details on how shipping costs were calculated).

Shipping costs for LNG imports were estimated for transport from Sakhalin, Russia to Nikiski. Under the Greenfield import scenario, newly built LNGCs with two-stroke diesel engines and LNG re-liquefaction would be used. Under this scenario, shipping 250 MMcfd to Alaska from Sakhalin would require one Q-flex LNGC (~220,000 cu m). Under the Brownfield import scenario it is assumed that two existing steam turbine-driven 89,900 cu m LNGCs would be used. These LNGCs have been significantly depreciated and are thus available at a lower charter rate than new build LNGCs.

While LNGCs are assumed to be filled to capacity under all export scenarios, for import scenarios, delivery volume varies with demand and Cook Inlet production. Import volumes were estimated based on demand estimates from Enstar and estimated reductions in Cook Inlet production from AGDC. Import volume in 2019 was estimated to be 132 MMcfd, with assumptions of sufficient storage capacity to meet seasonal demand swings. Import volume was capped based on the import terminal capacity of 250 MMcfd (equivalent to approximately 91 Bcf/yr or 93,500 BBtu/yr) – a level projected to be reached in 2030. For shipping costs, it is assumed that LNGCs dedicated to the project are sized to provide 250 MMcfd, and carriers are not filled to capacity during the years of import volume increases. Shipping fuel costs were adjusted to reflect higher costs per MMBtu for years with deliveries at less-than-capacity.

Table 21 shows estimated shipping costs for each export and import scenario given an oil price of $80 per barrel.

Table 21. Shipping Costs for Deliveries at LNGC Full Capacity

Volume	Trade Route	# and Capacity of LNGCs	2011$/ MMBtu
Export Scenarios			
1.6 MMTPA (250 MMcfd), Greenfield, new carriers	Alaska to S. Korea	1 x 220,000 cu m	0.75
3.1 MMTPA (500 MMcfd), Greenfield, new carriers	Alaska to S. Korea	2 x 220,000 cu m	0.75
4.7 MMTPA (750 MMcfd), Greenfield, new carriers	Alaska to S. Korea	3 x 220,000 cu m	0.75
1.5 MMTPA (240 MMcfd), Brownfield, current carriers*	Alaska to S. Korea	2 x 89,900 cu m	0.85
Import Scenarios			
1.6 MMTPA (250 MMcfd), Greenfield, new carriers	Russia to Alaska	1 x 220,000 cu m	0.62
1.5 MMTPA (240 MMcfd), Brownfield, current carriers*	Russia to Alaska	2 x 89,900 cu m	0.72

Note: Fuel costs are estimated when oil is at $80 per barrel.

The shipping costs shown in Table 21 represent both the charter cost of the LNGC (capital charge, crew, maintenance, insurance, etc.) and the fuel costs. Fuel costs are sensitive to the price of oil. In the model, shipping costs were projected forward by the indexing the fuel cost portion to the price of oil. When oil is $80 per barrel, fuel costs make up approximately 50 percent of the shipping cost of new-build two-stroke diesel powered LNGCs. Thus under the Alaska to South Korea export scenario, shipping costs would increase from $0.75 to 0.84 per MMBtu, or an increase of 12.5%, if the oil price were to rise by 25% from $80 to 100 per barrel. The existing 89,900 cu m LNGCs, which are used in the Brownfield import and export scenarios, are more sensitive to changes in the price of oil because the charter cost makes up lower share of the total shipping cost. Fuel costs for the existing 89,900 cu m LNGCs make up roughly 70 percent of total shipping costs when oil is $80 per barrel. Thus, if the oil price rises by 25% to $100 per barrel, shipping costs would rise by 17.5% from $0.85 to 1.00 per MMBtu.

Further, under the import scenarios, the older carriers modeled in the Brownfield scenario have proportionately higher shipping costs for the partial loads carried from the first delivery until 2030. This makes the Brownfield import scenario more sensitive to import volume changes.

4.1.8.3 Municipal Property and Sales Taxes

In Alaska millage rates for annual ad valorem property taxes vary by borough and service area but are capped at 3 percent by State law. Each borough adjusts its millage rate on an annual basis based on budget needs, expected revenue from other sources, and the total assessed value of property in the borough. The mill rates apply to the full assessed value of real property (value of land + improvements – depreciation). In Nikiski and Fairbanks, business inventories are exempted from real property. There is no Alaska state sales tax but boroughs have the right to levy individual sales taxes.

The proposed project site at the existing LNG export terminal in Nikiski is located in the overlapping Nikiski Fire and Nikiski Senior service areas of the Kenai Borough. In 2010 the total mill rate for this area was 10.12, a 12-year low.[50] From 2006 through 2010, mill rates in the area of the proposed terminal ranged from a low of 10.12 to a high of 13.20, with an average mill rate of 11.3840.[51] This average mill rate will be assumed for the purpose of modeling property taxes at the proposed terminal site in Nikiski. In Nikiski, property taxes are charged even during the construction phase and the fair market value is assessed by estimating the percentage of the project that is complete based on a construction schedule.[52] By Kenai Peninsula ordinance, the terminal's LNGCs would not be taxable as they are not expected to be kept or used in the Kenai Peninsula for more than 90 days per year (equivalent to one delivery every four days).[53] The sales tax in the Kenai Peninsula Borough is 3 percent. [54] In the economic model, the Kenai Peninsula sales tax is applied to the value of the EPC contract for the expansion of the Nikiski export terminal and to the value of inlet gas purchased at the terminal.

The project site 15 miles northwest of Fairbanks is located in a part of the Fairbanks-Northstar Borough that does not belong to a fire service area.[55] Because the land is owned by the State it has not previously been subject to municipal property taxes. For the modeling purposes, it will be assumed that the land will be sold to a private company for development of the LNG liquefaction project and that the nearby Chena-Goldstream Fire District will be expanded to serve the facility. In 2010 the mill rate for Chena-Golstream was 14.5760. From 2006 through 2010, mill rates for this area ranged from 14.2470 to 15.9739, with an average mill rate of 14.8476.[56] This average mill rate will be assumed for the purpose of modeling property taxes at the proposed terminal site in North Pole. There is no sales tax in the Fairbanks-North Star Borough.

Kenai property taxes were applied to the total project value of the Tidewater scenarios. For the Fairbanks scenarios, Fairbanks and Kenai property taxes were applied based on the estimation that 90% of the capital assets are to be located in Fairbanks with the remainder located at tidewater.

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[50] *"2010 Mill Rate."Assessing Department. Kenai Borough. http://www.borough.kenai.ak.us/assessingdept/Forms/2010MillRate.pdf (February 4, 2011) and "Mill Rates by TAG." Assessing Department. Kenai Borough. http://www.borough.kenai.ak.us/assessingdept/Forms/MILL%20RATES%20by%20TAG.pdf (February 4, 2011)*

[51] *Ibid.*

[52] *Kenai Borough Assessing Department, Frequently Asked Questions: "My house (or new construction project) is not 100% complete. Is it assessable when it is not complete?" http://www.borough.kenai.ak.us/assessingdept/FAQ.htm#4%20boat (February 4, 2011)*

[53] *Kenai Borough Assessing Department, Frequently Asked Questions: "What makes my vessel taxable?" http://www.borough.kenai.ak.us/assessingdept/FAQ.htm#4%20boat (February 4, 2011)*

[54] *AS 29.45.090 as referenced in Alaska Department of Commerce, Community & Economic Development. "Alaska Taxable 2010." January 2011. Page 15-16. http://www.commerce.state.ak.us/dca/osa/pub/10Taxable.pdf (February 4, 2011)*

[55] *Fairbanks North Star Borough Department of Community Planning. "Fairbanks North Star Borough Fire Service Areas." Information current as of May 2010. ftp://co.fairbanks.ak.us/Maps/Maps/Fire%20Service%20Maps/fire_service_area2.pdf (February 4, 2011).*

[56] *FNSB Division of Treasury and Budget. "Property Summary: 0801 Goldstream Valley." Updated: 02/04/11 04:00 AM, http://co.fairbanks.ak.us/Assessing/propacctsum.aspx?idx=200441 (February 4, 2011).*

4.1.8.4 Carbon Costs

In recent decades, the use of market-based mechanisms to cost-effectively reduce emissions has gained momentum as an alternative to traditional command-and-control systems. In the United States, experience with the market mechanism of emissions trading dates back to the mid 1970's with the introduction of the EPA's Emission Trading system, which sought to provide emitters greater flexibility in achieving compliance with air emissions standards. Widely regarded as the most successful emissions trading program implemented in the United States to date, the Acid Rain Program introduced under Title IV of the Clean Air Act Amendments of 1990 featured a cap-and-trade emissions trading program with bankable allowances that proved extremely effective at reducing SO_2 emissions from electricity generating plants.

Recent market based approaches to reducing greenhouse gas (GHG) emissions have focused on controlling the six GHGs targeted by the Kyoto Protocol using two mechanisms: 1) emissions allowance trading among entities with an emission cap and 2) trading in project-based GHG emission reductions. In a cap-and-trade system, a centralized authority sets an absolute limit on the quantity of emissions that can be emitted by a given pool of emitters. Within that pool, individual emitters are allocated emissions allowances (or credits), which collectively add up to the total quantity of emissions set by the cap. Individual emitters can then transfer allowances amongst themselves, enabling those entities that can more cost-effectively reduce their emissions to sell or trade their allowances to those for whom achieving reductions would be more costly. Project-based reductions provide entities an opportunity to achieve their allowance requirements by sponsoring or purchasing reductions achieved from a project that occurs outside of the pool of emitters established in the cap-and-trade program (offsets). Another option for regulating GHG emissions is a carbon tax applied to coal-, gas-, and oil-based fuels.

The 110th (2007-2009) and the 111th (2009-2011) Congress both proposed climate legislation that would have established nation-wide GHG cap-and-trade emissions trading programs. Of the legislation introduced the bill that came closest to passing was the American Clean Energy and Security Act of 2009, H.R. 2454, also known as the Waxman-Markey bill or ACES. The bill passed in the U.S. House of Representatives but did not pass in the Senate. Waxman-Markey included an economy-wide GHG cap and trade system and would have allowed a portion of the cap to be met by both domestic and international offsets. The EPA's economic analysis of H.R. 2454 projected that allowance prices for that bill would be \$13 to \$24 per metric ton CO_2 equivalent (tCO_2e) in 2013 and \$16 to \$30/tCO_2e in 2020.[57]

A number of regional cap-and-trade programs have emerged in the U.S., including the Regional Greenhouse Gas Initiative (RGGI) in the Northeast, the Western Climate Initiative (WCI) in the western states and Canadian provinces, and the State of California's cap-and-trade program linked to AB32, the California Global Warming Solutions Act of 2006. The latter two programs are still in development but RGGI, which sets a cap on emissions of CO_2 from electric power plants (and allows for allowance trading and the limited use of offsets), holds the distinction of

[57] *EPA Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the 111th Congress, Environmental Protection Agency (EPA), June 23, 2009.*

being the first mandatory GHG cap-and-trade program in the U.S. The value of allowances on RGGI was $3.2 per tCO2e in 2008 and $2.7 in 2009.[58]

The largest market-based GHG emissions trading system in operation at this time is the European Union Emissions Trading Scheme (EU ETS), which caps CO_2 emissions from approximately 11,000 installations in the EU and represents about 50 percent of EU-wide CO_2 emissions.[59] The value of allowances on the EU ETS has fluctuated a great deal since its launch in 2005, with a value of US$32.5 tCO_2e in 2008 dropping to US$18.7 in 2009.[60]

In previous analysis of proposed Federal GHG legislation SAIC found that the impacts of proposed legislation on the U.S. economy will be heavily dependent on the features and functionality of legislative provisions allowing market mechanisms, such as carbon offset projects and a tradable carbon allowance market. If offsets are authorized, the number of offsets available will make a very large difference in domestic economic impacts, almost as much as the choice of technologies used to curb emissions. A future price on carbon will be determined by the design of legislation to regulate greenhouse gas emissions, point of regulation, the distribution of allowances and the rules around use of offsets will all be key factors. It is difficult to predict how the regulatory environment will evolve over the next several decades.

A number of GHG intensive industries are anticipating a future cost of carbon and have begun incorporating it into their long-term decision-making. The Edison Electric Institute recently expressed support for a cap-and-trade regime and a price on carbon,[61] and Exxon Mobil's 2010 annual energy outlook report stated that the company was anticipating a carbon price of $30 per tCO_2e by 2020 and $60 per tCO2e by 2030 in OECD countries.[62] For the purposes of this analysis, the ExxonMobile annual energy outlook report projections of $/ tCO_2e is used assuming a linear increase from 2020 and 2030 that both pre-dates and post-dates this time period. In addition to the carbon price escalations projected by ExxonMobile in 2010$, these prices are further are escalated by 3% annually to adjust for inflation.

To estimate CO_2 emissions, CO_2 removed in treating was combined with the estimated CO_2 created by combustion of fuel gas. The CO_2 emissions from combustion are based on 110 lbs per MMBtu burned. These estimates do not include transportation emissions.

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[58] *The World Bank. "State and Trends of the Carbon Market 2010," May 2010 http://siteresources.worldbank.org/INTCARBONFINANCE/Resources/State_and_Trends_of_the_Carbon_Market_2010_low_res.pdf*

[59] *European Commission Climate Action website, http://ec.europa.eu/clima/policies/ets/index_en.htm, accessed February 8, 2011.*

[60] *The World Bank. "State and Trends of the Carbon Market 2010," May 2010 http://siteresources.worldbank.org/INTCARBONFINANCE/Resources/State_and_Trends_of_the_Carbon_Market_2010_low_res.pdf*

[61] *Ling, Katherine, "Utilities expect Congress to eventually set carbon price – EEI chief," Climatewire, January 12, 2011, http://www.eenews.net/eenewspm/2011/01/12/archive/5?terms=utilities+expect+Congress+to+eventually+set+carbon+price.*

[62] *Exxon Mobil. "2010 The Outlook for Energy: A View to 2030," http://www.exxonmobil.com/Corporate/energy_outlook_view.aspx*

4.2 MODEL RESULTS

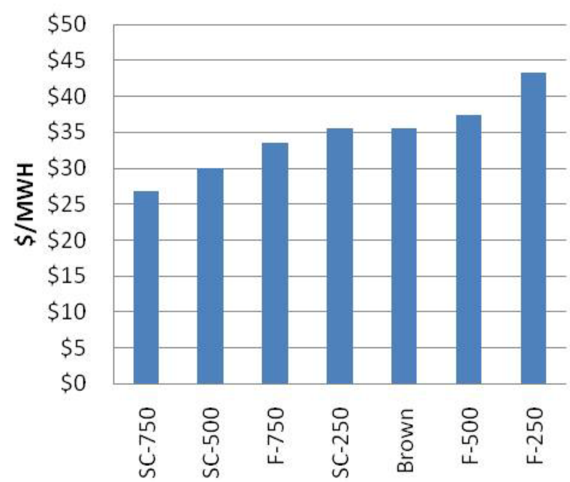
4.2.1 Export Scenario Base Case Results

North Slope netback represents the highest price a project can pay for North Slope gas and still be economically viable. Figure 22 shows North Slope netback in 2011$, with pipeline operations commencing in 2016 and 2019, and with levelized, nominal pipeline tariffs in Southcentral of $7.90, $6.67, and $6.03 per MMBtu for 250, 500, and 750 MMcfd plant inlet volumes, respectively. The same tariff was applied for Greenfield 250 MMcfd and Brownfield 240 MMcfd. The Fairbanks tariff is $6.25, $5.15, and $4.74 per MMBtu for 250, 500, and 750 MMcfd plant inlet volumes, respectively. Netback values are higher with a lower tariff, and hence are also higher with commencement of operations in 2019 versus 2016. This difference is a result of the 3% per year price escalations between 2016 and 2019 while the tariff was held flat.

Larger facilities have consistently higher netback prices than smaller facilities at the same location. The larger projects are able to take advantage of greater economies of scale, hence their capital costs are lower on a $/ton basis. Further, the larger facilities at the Tidewater site in Southcentral have lower tariffs. Southcentral sites have a higher North Slope netback than the Fairbanks sites. This is largely due to the higher capital costs in Fairbanks and rail transportation of LNG from Fairbanks to tidewater.

Figure 21. North Slope Netback with Operations beginning in 2016 and 2019

Figure 22. Cogeneration Busbar Price



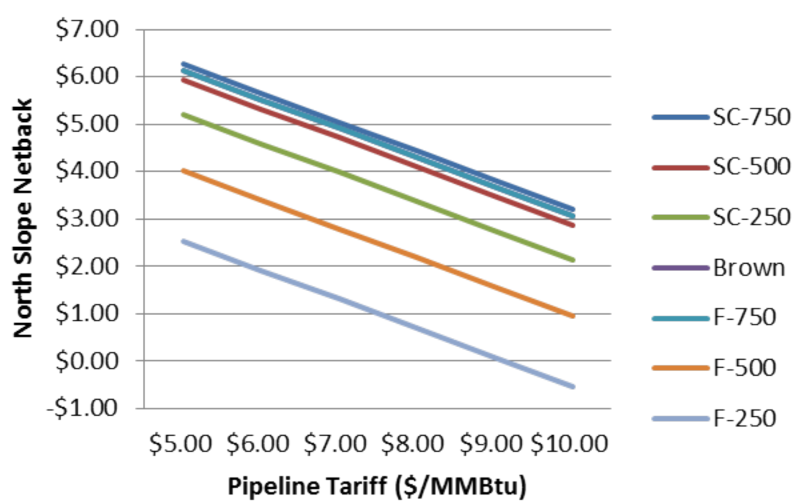
X-Axis Key: F = Fairbanks Greenfield; SC = Southcentral Greenfield; Brown = Brownfield; numbers refer to 250, 500, and 750 MMcfd throughput capacities.

Figure 23 shows busbar prices for the power cogeneration components of the modeled facilities. Because busbar costs included only incremental cost increases over a base facility without cogeneration, there are no fuel prices associated with the busbar prices (and no rail costs for the Fairbanks scenarios). As a result, the pipeline tariff does not affect busbar costs. Further, these results do not change with the project start date when expressed in nominal dollars (all model results are expressed in 2011$). This is because all cost elements of the cogeneration scenario are inflated at the same rate. While busbar power costs vary among generators within the Railbelt, these costs are commonly around $40 to $50 per MWH, suggesting that cogeneration opportunities at Alaskan LNG liquefaction facilities may be economically feasible.

4.2.2 Sensitivity to Oil Price, North Slope Price, and Pipeline Tariff

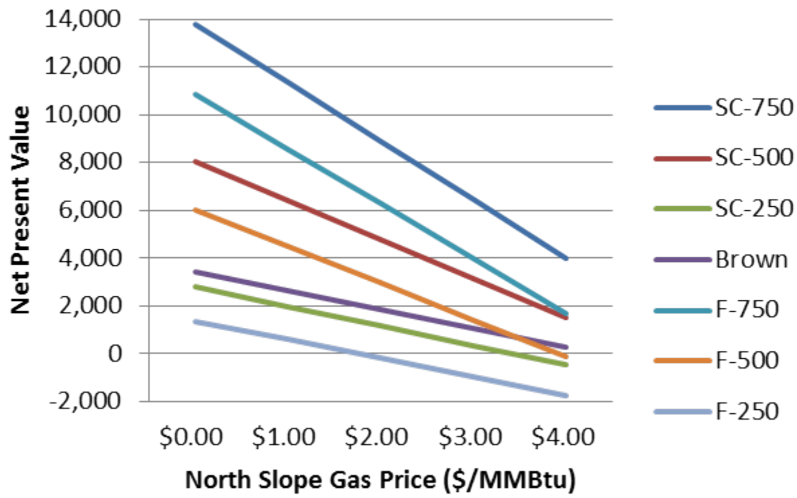
The effects of three variables on economic viability were assessed: oil price, North Slope gas price, and pipeline tariff. For each sensitivity analysis, all but the tested variable were kept as shown in Table 17. The effect of tariff on North Slope netback is similar for all scenarios, as indicated by the parallel lines of Figure 24.

Figure 23. Pipeline Tariff Effects on North Slope Netback



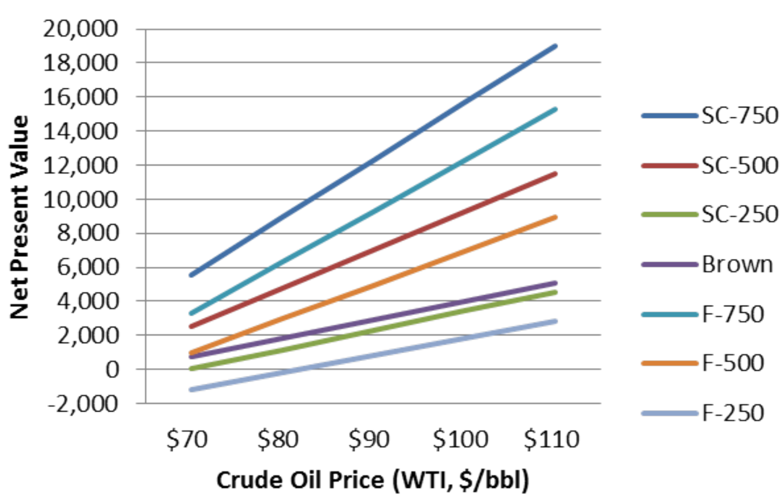
The effect of North Slope gas price on net present value (NPV) is shown in Figure 25. While all scenarios have a positive NPV with North Slope gas prices of $1.00/MMBtu and less, the smallest Fairbanks scenario loses viability at North Slope prices around $2.00 /MMBtu. The smaller-size Southcentral scenarios lose viability between $3.00 and $4.00.

Figure 24. **North Slope Gas Price Effects on Net Present Value**



Oil prices affect the price of LNG, and hence revenues, in addition to the cost of shipping and rail transport costs. The effect of initial oil prices ranging from $70 to $100/barrel of West Texas Intermediate (WTI) on project net present value (NPV) is shown in Figure 26 based on an initial North Slope gas price of $2.00 in 2011$. Both North Slope gas price and oil prices are inflated at a rate of 3.0% annually. The NPV of larger facilities is more sensitive to LNG prices than the smaller facilities. While the small Southcentral scenarios require an initial oil price of around $70/bbl, the small Fairbanks scenario requires an initial oil price that is nearly $20 higher under the set conditions. The larger-sized Fairbanks scenarios also require higher oil prices than the larger Southcentral scenarios, but difference in minimum requirements is less, around $10/bbl.

Figure 25. **Crude Oil Price Effects on Net Present Value**



4.2.3 Import Scenario Base Case Results

The three import scenarios have very similar results with respect to the cost of gas at the distribution line entry point. The cost of gas at the distribution entry point includes costs of both regasification and LNG (Figure 27), and is significantly affected by the price of oil (Figure 28).

Figure 26. Imported Gas Cost at Distribution System Entry ($/MMBtu), WTI=$80/bbl

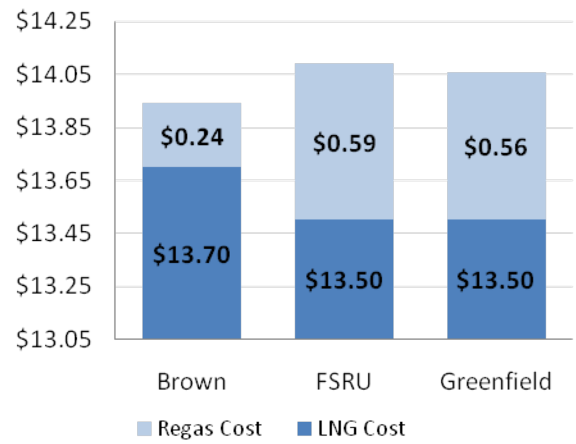
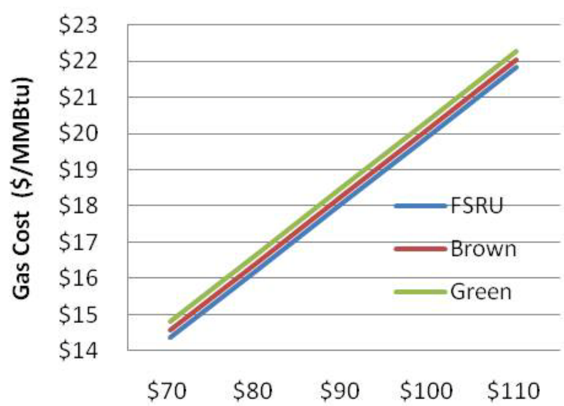


Figure 27. Oil Price Effect on Import Gas Cost at Distribution System Entry



While the capital costs of the Greenfield Onshore regasification scenario are substantially greater than the other regasification scenarios, i.e., $470 million versus $141 million and $79 million for Brownfield and FSRU options, respectively, all three scenarios have similar gas cost at the distribution point. This is a result of the very large proportion of costs that are LNG costs, as seen in Table 22. The 20-year present value of combined financing and non-LNG costs do not exceed 3% of total costs.

Table 22. Regasification Scenarios: 20-Year Present Value of Revenue and Cost Components ($ millions)

		Expenses *(% of total costs)*		
Scenario	**Revenue**	**LNG**	**Non-LNG OpEx**	**Financing**
FSRU Offshore Regasification	$38,707	$36,995 *(96.2%)*	$1,329 *(3.5%)*	$132 *(0.3%*
Brownfield Onshore Regasification	$38,615	$36,995 *(97.3%)*	$235 *(0.6%)*	$787 *(2.1%)*
Greenfield Onshore Regasification	$37,162	$36,453 *(98.6%)*	$281 *(0.8%)*	$236 *(0.6%)*

If the regasification terminal is operated as a tolling facility in which the terminal owner is responsible for processing the LNG but never takes ownership of the LNG or gas, the terminal owner's risk will be greatly reduced. This is because the terminal owner would not be responsible for the relatively large costs (and risks) associated with LNG purchases. In general, lower risk projects are able to obtain more favorable financing and can more readily gain the interest of potential investors. Under a tolling ownership model, the LNG may be purchased directly by a company such as ENSTAR.

4.3 CONCLUSIONS

This analysis suggests that the economies of scale that can be achieved with Greenfield 500 and 750 MMcfd LNG facilities may be more economically favorable than the Brownfield export scenario, under which the Kenai LNG Plant is maintained at current capacity. In addition to reducing the cost of liquefaction and shipping through economies of scale, the larger export plants would also reduce the per-unit tariff of the pipeline from North Slope by spreading the pipeline's capital charge out over more units of gas. As a result, consumers in Southcentral Alaska would pay a lower tariff per unit of gas consumed under the larger, Greenfield scenario because more of the pipeline's tariff revenue would come from LNG exports. In other words, a larger share of the pipeline's cost (recouped through the tariff) would be paid for by Asian LNG importers rather than Alaskan businesses and residents.

The findings in this report are largely influenced by the distinct scenarios that were chosen for analysis. Some variations of the scenarios in this report may be preferable. For instance, among the scenarios not analyzed by this study is the possibility of expanding the existing 240 MMcfd Kenai plant to 500 or 750 MMcfd rather than building a Greenfield plant. These scenarios could be achieved by refurbishing the Kenai plant's existing equipment and constructing additional LNG production trains and storage capacity. "Partial Brownfield" scenarios would leverage existing assets to reduce the overall investment requirements and could reduce the project risk associated with permitting, safety and environmental considerations at a Greenfield site.

Regardless of whether the 500 and 750 MMcfd scenarios are Greenfield or partial Brownfield construction, the capital investment required would be substantially greater than the cost of refurbishing the existing Kenai facility and operating it at current capacity. From an investment standpoint, greater investment represents greater risk, and greater risk typically requires a higher cost of capital. The scenarios modeled in this analysis all use the same cost of equity and cost of debt (12% and 6.5% respectively), which falsely suggests similar risk regardless of the size of investment. It is reasonably likely that the cost of both equity and debt would be greater for 500 and 750 MMcfd LNG facilities (Greenfield or partial Brownfield) than for a Brownfield 240 MMcfd facility. Further analysis would be required to estimate the difference in the cost of capital between the Greenfield and Brownfield scenarios but the magnitude of this difference could potentially affect the relative economic ranking of these scenarios.

A larger-capacity LNG export facility may also have unintended consequences for the North Slope price of gas at North Slope. Greater demand for North Slope gas may reduce the availability of “cheap” gas for use in oil production, thus potentially reducing the volume of economically recoverable oil reserves. Competition for North Slope gas could lead to North Slope price increases, thus impacting the economic viability of the pipeline and LNG export projects. Under such circumstances, a bigger LNG facility and a bigger pipeline may not always be better.

Overall, the results of this study suggest that refurbishment and operation of the existing Kenai LNG plant at current capacity may provide a viable anchor customer for the Stand Alone Gas Pipeline. Larger Greenfield LNG anchor customers may produce more favorable economic returns than a 240 MMcfd Brownfield anchor due in large part to the pipeline tariff reduction associated with greater volume. However, this should be viewed with caution recognizing that the more favorable economics of the larger Greenfield plants are based on assumptions that investors will view the substantially different capital investments as having similar risk, and producers will not view either of these demand levels as affecting North Slope oil production. A final determination of the optimal-size anchor customer will be ultimately based on the perspectives of both North Slope producers and potential LNG investors.

The purpose of this study was to assess the feasibility of an LNG export terminal to act as an anchor customer for a gas pipeline that would bring new supply to Southcentral Alaska where existing production is in decline. This study included a high-level analysis of another option to cover this supply shortfall -- importing LNG to Southcentral Alaska to meet demand. The cost of meeting Alaskan natural gas demand with imported LNG provides a ceiling under which the costs of North Slope pipeline gas must fall for an in-state pipeline to be economically viable.

Further analysis is needed to confidently determine whether importing LNG or exporting LNG would be an optimal way of obtaining new supply. Such an analysis should involve a more complete cost-benefit study that takes into account potential subsidies and sponsorship of the pipeline, the expected increase in tax revenue from increased resource production on the North Slope, the economic and employment impact of pipeline and LNG terminal construction, and a comparative analysis of the price impacts under the import and export scenarios. Such an analysis would need to look at these issues from multiple perspectives, including the State, Alaskan gas consumers, Alaskan gas producers, and other stakeholders. This type of analysis is critical as the choices Alaska makes today regarding its energy future will have significant impacts on Alaskans for decades to come.

5. PROJECT SCHEDULE

For LNG liquefaction (export) projects, the estimated schedule duration for project permitting, design, and build is 5 years for the projects at Tidewater, and 6 years for the projects at Fairbanks. Time estimates for the Tidewater projects are:

- Permitting – 1 year
- Front End Engineering and Design – 1 year
- Construction – 3 years

Construction components with long lead times (e.g., LNG storage tanks) would be firmed up during years 1 and 2. While 3 years construction is estimated for the liquefaction and LNG storage facility, the cogeneration component (which may have a separate owner) may only require 2 years construction. For the Fairbanks scenario, an additional year is expected to be needed to allow for the development, building, and testing of a system for loading and offloading LNG from hundreds of rail cars within a 24-hour period.

For the Greenfield onshore regasification project, the estimated schedule duration for permitting, design, and build is 4 years:

- Permitting – 1 year
- Front End Engineering and Design – 1 year
- Construction – 2 Years

Brownfield onshore regasification and FSRU scenarios are estimated to have schedule durations of 3 years.

Appendix A: List of Interviewees for Siting Assessments

The following organizations were contacted regarding LNG facility siting locations. Representatives that were at these interviews are listed below. Most interviews were conducted in person. All interviews were conducted between January 11 and 15, 2011.

Alaska Department of Natural Resources (DNR)
Kurt Gibson, Petroleum Investment Manager, Deputy Director

Alaska Natural Gas Development Corporation (ANGDA)
Harold Heinze, Chief Executive Officer
Kaye Laughlin, Permitting Coordinator
Kirsten Sikora, Administrative Officer

Alaska Railroad Corporation
Tom Brooks, Vice President, Engineering,
Roy Thomas, Director, Engineering Services

City of Seward
Phillip Oates, City Manager
Donna Glenz, Planning, Zoning, and Land Use

ConocoPhillips
Dan Clark, Manager, Cook Inlet Assets
Von Hutchins, Director, Gas Supply and Marketing, Cook Inlet Assets
Michael Spangler, Operations Manager Cook Inlet Area
Peter Micciche, Superintendent, Kenai LNG Facility

ENSTAR Natural Gas Company
Mark Slaughter, Manager, Gas Supply

Fairbanks Economic Development Corporation
Paul Mertz, Energy Programs

Fairbanks North Star Borough Department of Community Planning
Bernardo Hernandez, Director
Jim Lee, Deputy Director

Golden Valley Electric Association
Mike Wright, Vice President, Transmission & Distribution
Kathryn Lamal, Vice President, Power Supply

Kenai Borough
Gary Williams, Coastal District Coordinator

Matanuska-Susitana Borough
Eileen Probasco, Chief of Planning
Susan Lee, Planner II
David Hanson, Economic Development Director
Marc Van Dongen, Port Director

Southwest Alaska Pilots Association
Captain Jeff Pierce, President
Tyonek Enterprise Development, Inc.
John McClellan

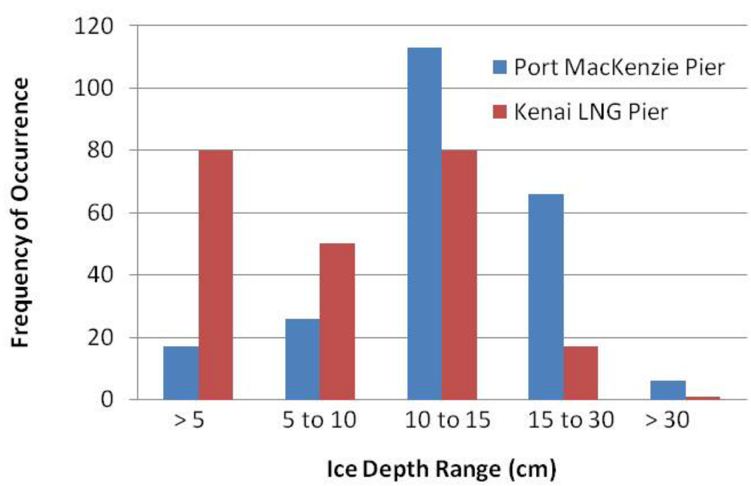
U.S. Coast Guard
Captain Jason Forsdick, Sector Commander Anchorage
Paul Albertso, Deputy Sector Commander Anchorage

Appendix B: NOAA Ice Data Analysis for Nikiski and Port MacKenzie

The NOAA Anchorage office collects data for graphic analyses of sea ice in Cook Inlet. Data has been collected three days per week since December, 2007. Graphical analysis (i.e., ice maps) developed from this data are published on the NOAA website at http://pafc.arh.noaa.gov/ice.php. The NOAA Anchorage office provided SAIC with the GIS shape files used to develope their ice maps from December 3, 2007 through January 31, 2011. Data for Port MacKenzie and Nikiksi coordinates was extracted from these files to compare ice thickness and percent ice coverage at these sites. There were 228 measurement dates with ice recorded in one or both of these sites.

Measurements for ice depth are recorded as “ice age” based on depth range, i.e., new ice (0 to 10 cm); young ice (10 to 30 cm), etc. Several ice ages are sometimes recorded for a location on a given date. The average depth was calculated for each location and date based on the average of the range midpoints. Calculated average ice depths were ranked (i.e., placed in range categories), and a frequency distribution was created, as shown in Figure 29. The average ice depth range for Port MacKenzie is 10 to 15 cm, while the average ice depth range for Nikiski is 5 to 10 cm.

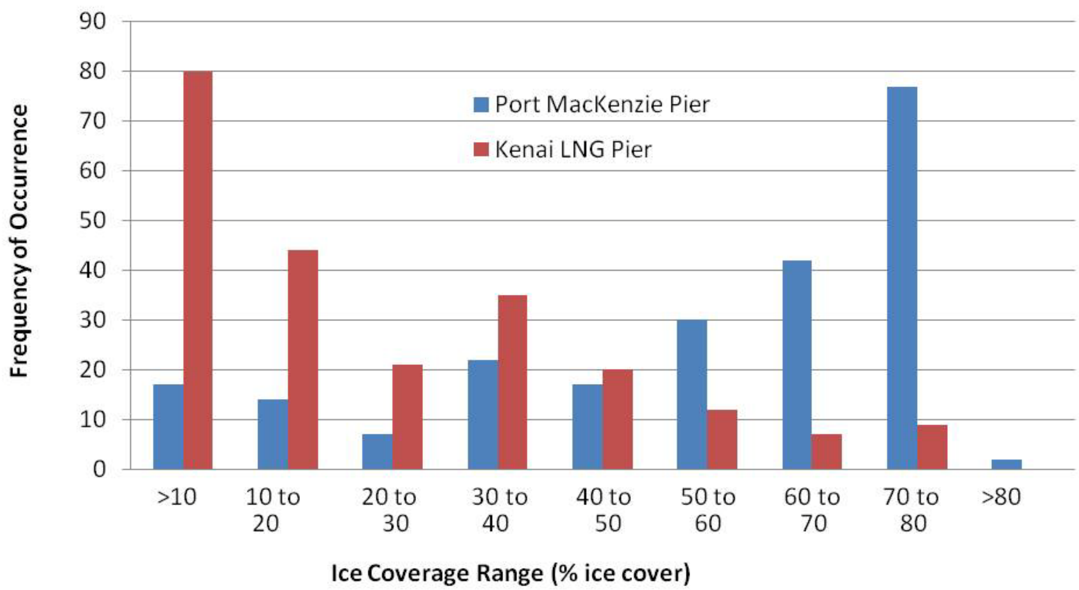
Figure 28. Ice Depth Range at Port MacKenzie and Nikiski, Frequency of Occurrence between December 2007 and January, 2011



Ice coverage, or “concentration”, as referred to in the NOAA dataset, is recorded as a range that typically spans 20 to 30 percent (e.g., 20 to 40%, 70 to 100%). The average ice coverage was calculated for each location and date as the range midpoint. Calculated average ice coverages were ranked (i.e., placed in range categories), and a frequency distribution was created, as shown in Figure 30. The average ice coverage range for Port MacKenzie is 40 to 50%, while the average ice coverage range for Nikiski is 10 to 20%.

The combination of ice depth and coverage conditions that may cause delays in LNGC deliveries was not determined in this analysis. However, since no ice-related delays have been reported in the 40 years of LNG voyages from Nikiski, potentially hampering conditions are assumed to occur under more extreme conditions than are common at Nikiski. In the 4 years of NOAA data, average ice depths in excess of 15 cm occurred in conjunction with ice coverage greater than 70% occurred at Nikiski on 4% of the measurement dates (i.e., dates in March, 2009 and December, 2010). Similar or more extreme conditions occurred on 27% of the measurement dates in Port MacKenzie (i.e., dates in January of each year, 2008 through 2011; in addition to dates in February and March 2009, and February and December in 2010). The more common extreme conditions at Port MacKenzie suggests the possibility of ice-related delays in LNG deliveries from this site.

Figure 29. **Ice Coverage at Port MacKenzie and Nikiski, Frequency of Occurrence between December 2007 and January, 2011**



Appendix C: Capital and Operating Cost Estimates

LNG Terminal Cost Estimates

Developing a cost estimate for a new natural gas liquefaction plant is a very difficult process and cannot be accomplished with any degree of precision without investing the time and money in detailed analysis of the liquefaction processes available, utility costs, feed value, product value, labor costs, current state of the EPC market, transportation variables, site variables including geo-technical and metocean, and the commercial structure of the project. Typically, companies spend 5 to 25 million dollars performing a pre-FEED (Front End Engineering and Design) study to develop a reasonable cost estimate (+/- 25%) before making an investment decision. As with all large energy projects, a key part of the pre-FEED and FEED is optimizing a design that balances higher front-end capital costs with the present worth of future savings from higher efficiency and lower operating costs. This optimization process or life-cycle analysis can result in significantly different capital costs depending on the margin available between the feed gas and the LNG product.

Although the number of LNG plants has grown tremendously over the last 50 years, liquefaction plants are not standardized off- the-shelf items and are specifically designed for each project (add-on process trains at the same location are the exception). That fact plus the limited number of EPC contractors in the world capable of designing and building these unique facilities make their specific cost, expressed as dollars per Metric tonne of annual LNG capacity ($/MTA), highly variable.

In general, average LNG plant costs were in the $300 to $800/MTA range in the early 90's and began coming down in the late 90's and early 00's primarily because the plants were getting larger and specific costs were coming down due to economies of scale. In a recent review of LNG economics, the differences between actual and published costs were noted, with published costs typically being higher than actual costs. The reviewers noted that "realistic" new plant costs ranged from $200 to $375/MTA in 2005 (average cost: $258/MTA).[63] There has been little detailed cost information published recently, but our sense of the general feeling in the industry is that current costs have risen to $500 to $1200/MTA. The increase is primarily due to higher material and labor costs, busier EPC contractors, smaller proposed plants, and plants that are more complex and flexible. Finally, we note that EPC contractors are very reluctant to provide preliminary or budgetary estimates given the myriad of variables and volatility of the market.

Given the above challenges, R. W. Beck developed capital and operating cost estimates for the Alaska Gasline Development Corporation to allow netback analysis of exporting gas production from the North Slope. The estimate was a "top-down" estimate based on analysis and adjustment of publically available $'s/MTA cost values for other plants built over the past 5 years. We maintain a database on LNG projects derived from monitoring such public sources as industry

[63] Al-Saadoon, F.T., and A. U. Nsa, 2009. Economics of LNG Projects. Society of Petroleum Engineers, SPE 120745. Presented at the SPE Production and Operations Symposium in Oklahoma City, OK, April 4 – 8, 2009.

journals, press releases, and conference presentations. Of the 59 projects in our data set, the applicable data for this cost estimate is summarized in Table 23. Applicable data means there was a cost and capacity figure quoted that we believed was reasonable and did not include extraneous costs such as production development, shipping or upstream gas plants.

Table 23. Selected LNG Project Costs

Project	Location	Start-up	$/MTA	Comment
Soyo	Angola	2012	385	
Darwin	Australia	2006	556	
NW Exp, Train 5	Australia	2008	359	Add-on train
Damietta	Egypt	2005	433	
Idku	Egypt	2005	244	Add-on train
Tangguh	Indonesia	2009	184	Add-on train
Camisea	Peru	2010	364	
Kitimat	Canada	2013	580	Cost and capacity suspect
Al-Saadoon (2009)	5 Project average	+/- 2005	258	

The eight specific projects summarized above represent 14% of the population in our data base. We also reviewed professional papers published by the Society of Petroleum Engineers (SPE), the Offshore Technology Conference, and by EPC contractors. Presentations by operators and EPC contractors made at LNG conferences were also reviewed. In addition to a dearth of useful cost information, a significant issue with published numbers is determining exactly what the stated cost includes. In discussions with a knowledgeable source at a large LNG EPC company, we verified that published data may or may not include production development costs, upstream gas processing costs, shipping costs, owner costs, financing costs, offsite costs, development costs, jetty costs, and other very significant values.

A particularly useful paper published by KBR, Inc. provides costs per MTA for a range of six possible plants of increasing complexity.[64] However, the cost data is in an undefined “currency”. The generic plant had a capacity of 4.5 MTA and was assumed to be built in Africa. We assumed this to be West Africa. Based on the reviewed data, our EPC source, and our professional judgment, we concluded that the all-in cost of a Greenfield LNG facility including development and owner costs, financing, storage, and loading jetty was $300/MTA in 2005 for a 4.5 MTA plant of KBR complexity level two in Western Africa. Using published global cost indexes, we then adjusted that cost for location to a Houston, Texas location. We than adjusted the cost from 2005 to 2011 based on published construction cost inflation indexes. We did not estimate a specific cost increase for Houston to Alaska or distinguish between a Fairbanks or tidewater location to allow those factors to be applied in the economic model. The resulting specific costs for a Houston location (including financing) was $963, $636, and $498/MTA for the 250, 500 and 750 MMCFD plants. Although these figures may appear high considering the starting point of $300/MTA in

[64] *Kotzot, H., C. Durr, D. Coyle, and C. Caswell. LNG Liquefaction – Not All Plants Are Created Aqual. KBR Technical Paper PS4-1, as viewed at http://www.kbr.com/Newsroom/Publications/technical-papers/LNG-Liquefaction-Not-All-Plants-Are-Created-Equal.pdf*

2005, the EPC source mentioned above volunteered the opinion that a world scale (approximately 4 to 7MTA) liquefaction plant in Alaska would likely cost over $1,000/MTA in today's environment.

The final adjustment in the capital estimating process was to account for scaling. The base plant is assumed to have a capacity of 4.5 MTA. A larger plant would be expected to cost more but not in direct proportion to the capacity increase because of economies of scale. On the other hand, a smaller plant would be expected to cost less, but not proportional to the reduced capacity. Again, based on our experience with the cost of gas processing facilities and power plants, we applied a commonly used scaling equation known as the Rule of Six-tenths to decrease the specific cost ($/MTA) for the 750 MMCFD plant which is expected to produce approximately 4.7 MTA and increase the specific cost of the smaller 500 MMCFD (3.1 MTA) and 250 MMCFD (1.6 MTA) plants. The equation calculates the proposed plant cost by multiplying the base plant cost by the ratio of the proposed capacity to the base capacity raised to the 0.6 power. The product of each plants $/MTA times its annual estimated LNG production equaled the total capital dollars. Finally, because the economic model layers in financing costs, we reduced the above capital dollars by 11% to back out the estimated financing costs.

The total capital cost for each facility was broken down into Facility, Storage, and Loading/Jetty component costs using an average cost breakdown consistent with published data by operators and EPC contractors. Because we see a wide variation in the cost contribution of each of the three components in the published data, we must emphasize that the estimated cost of the components is less accurate than the total capital cost. The above component costs are Greenfield costs.

For the purposes of calculating cogeneration capacity, estimates of refrigeration and power consumption were developed based on specific horsepower and kilowatt per MTA estimated for a plant using the Conoco-Phillips cascade refrigeration process. These hp and KW totals were used to estimate the potential for cogeneration power by utilizing waste heat assuming the base plant turbines were operating in simple cycle. These process specifics were not utilized to build up a "bottom-up" capital cost estimate.

Operating costs for the LNG plants are high level estimates based on our experience with large gas processing plants and power plants and we would expect the precision of these values to be consistent with the total capital cost estimates.

In summary, we are of the opinion that the total capital costs for each plant scenario represent a Class 5 estimate as defined by the American Association of Cost Engineers and actual costs may be lower by as much as 50% or higher by as much as 100%.

Rail Transport Cost Estimates

The capital and operating cost estimates for rail transport from Fairbanks to an LNG terminal at Seward were based on very high level assumptions. We are not aware of any project to date that has attempted to transport such a large volume of cryogenic liquids on a continuous basis. Based on the estimated capacity of a known cryogenic rail car, we have estimated that two to four trains per day of 50 to 75 cars traveling each way (four to eight trains total) would be required to accommodate the LNG production from a Fairbanks plant (Table 24).

Table 24. Rail Transport of LNG

Plant Feed, MMCFD	Daily Trains South	Daily Trains North	Total Daily Trains	Total Cryogenic Cars
250	2	2	4	400
500	3	3	3	800
750	4	4	8	1200

We have assumed that the loading, travel, unloading and return cycle for each train can be accomplished in 24 hours. Simple calculations assuming each car is loaded or unloaded conventionally in series results in estimates of over 24 hours for simply loading or unloading a single train. We have assumed that a new system can be developed and installed for each feed scenario of \$50, \$70, and \$90 million respectively to make a 24 hour cycle possible and that is the basis for the estimates in Table 24. If a faster loading/unloading process cannot be developed, many more trains will be required and the capital costs could increase by an order of magnitude. Based on the 24 hour cycle, we also estimated diesel fuel consumption. These costs are significant, each train potentially consuming 38,000 gallons of diesel per round trip. (Note: fuel costs will be accounted for in the economic model.)

Because the technology for LNG rail transport operations of this magnitude have not been developed, we consider the capital and operating cost estimates for the rail transport to be beyond the American Association of Cost Engineers Class 5 level of accuracy and would bracket the costs at -50% and +300%. In our opinion, building an LNG plant that is dependent on rail transport for production disposition is not feasible with current technology.

Appendix D: Assessment of Financing Assumptions

This economic feasibility study uses assumed values provided by AGDC for the cost of debt (i.e., 6%), cost of equity (i.e., 12%), and debt to value ratio (i.e., 70%). The discussion below provides an independent review of the reasonableness of these assumptions.

For ease of comparisons, the same financing assumptions are used for AGDC's assessment of the Alaska Stand Alone Gas Pipeline and all the modeled potential anchor customers. However, the cost of capital generally increases with project size and complexity. Hence, smaller projects tend to have more favorable financing terms, as do pipelines compared to complex industrial facilities.

For the assessed LNG scenarios, the cost-of-debt, cost-of-equity, and debt-to-value ratios used in this economic feasibility study are found to be within the range of what is expected for LNG projects. However, given that these assumptions yield minimum Debt Service Coverage Ratios (DSRC) that are below typical lender thresholds of 1.4x and 2x, the appropriateness of a 70% debt-to-value for the modeled projects depends on several unspecified variables. These variables include the project's revenue model, the ability to establish a Debt Service Reserve Account (DSRA) to reduce the risks associated with a low DSRC, and other lender criteria. DSRA requirements could be relaxed with a reduced debt-to-value ratio and increased cost of capital. If the modeled projects are advanced to a more detailed planning stage, it is likely that financing terms would differ for each project, and these terms would affect the netback value of gas at North Slope.

Financing of LNG Projects

Large, capital-intensive LNG projects are typically financed under a project finance formula in which long-term project debt is secured by the project's physical assets and repaid solely through the project's revenue streams. Lenders often have no recourse or limited recourse to the balance sheet of the project's sponsors if a project fails to meet expectations. Project financing allows projects to reach high debt-to-value (leverage) ratios in the range of 60-80%. Long-term debt is raised in the form of syndicated commercial bank loans,[65] bond issues, and bridge and backup facilities.

Banks determine borrowing rates for LNG projects based on a number of factors including the length of the loan repayment and disbursement periods, the ratio of the loan to total project costs, the prevailing risk-free yield on long-term government bonds at the time the loan is issued, and a detailed analysis of the project's credit strengths and risks. The primary measure that lenders use to indicate a project's credit strength is the Debt Service Coverage Ratio (DSCR). DSCR is the cash available to pay debt in each period [66] – the higher the DSCR, the lower the risk to the lender.

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[65] A syndicated bank loan is a loan that is funded by a group of banks rather than just a single bank.

[66] DSCR is calculated as the ratio of cash flow before debt service (i.e., revenue less all operating expenses and taxes) to debt service (i.e. loan repayments).

A project with higher capital cost will have a higher debt service and a lower DSCR compared to a lower cost project with all other circumstances equal. Thus, lenders would require a higher interest rate on debt for the higher cost project or may only be willing to lend a lower percentage of the total investment costs. In the event that a senior lender would not be willing to meet the project's target leverage ratio (70%), the higher cost project would need to obtain subordinated debt at a higher interest rate to maintain the target ratio. As a result, more expensive projects are likely to have either lower debt-to-value or a higher cost of debt than less expensive projects.

Credit Ratings, Risk and Revenue Models

Credit ratings are an indicator of both economics and riskiness of a project. While DSCR is an indicator of project economics, assessments of overall project risk include consideration of project complexity and constructability, credit strength of the sponsor(s), strength of long-term agreements between buyers and sellers, market and price forecasts, operating risks, country risks, and force majeure risks.[67] Riskier projects need to meet higher economic thresholds as indicated by the minimum DSCR that is set by the lender. Equity investors make similar determinations on project economics and risk to determine required returns.

Project risk is significantly affected by the project's revenue model. There are three basic revenue models for LNG export projects:

- **Integrated Model** – under the integrated model, the gas producer owns the LNG terminal, produces and liquefies the gas, and sells it to the buyers. Under this model, the LNG terminal owner assumes all risks of gas production, liquefaction, shipping, and sale price volatility.
- **Merchant Model** – under the merchant model, the gas producer and LNG terminal owner are different companies. The LNG terminal buys gas from the producers, liquefies the gas, and ships it to the buyers. Under this model, the LNG terminal owner assumes all the risks of gas liquefaction, shipping, and sale price volatility.
- **Tolling Model** – under the tolling model, the LNG terminal owner provides the service of gas liquefaction, but never actually owns the gas. The producers sell gas directly to the Pacific Rim buyers, and pay a set tariff to the terminal company for gas liquefaction, storage, and possibly shipping services. Under the tolling model, the LNG terminal owner only assumes the risks of providing liquefaction (and possibly shipping) services.

The greater risks of merchant and integrated revenue models result in more volatile revenue streams, which cause lower credit ratings than tolling projects. As a result, the minimum required DSCR is typically higher for merchant and integrated models than for tolling models. According to the credit rating agency Standard & Poor's (S&P), debt from merchant projects must typically have a DSCR of 2.0x or higher to achieve an investment grade credit rating. Under tolling models, by contrast, S&P typically requires a minimum DSCR of 1.3-1.5x to reach investment grade status.

[67] "Financing LNG Projects – Breakout Sessions #6 and #7." Goldman Sachs. March 30, 2008. Slide 2. http://www.gov.state.ak.us/agia/pdf/presentations/Financing%20LNG%20Projects.pdf (April 12, 2011)

Often LNG export projects operate under merchant or integrated models because they are developed by large oil and gas majors with ample cash and a general comfort with revenues that are based on volatile energy prices. Tolling models are more common for LNG import terminals. It should be noted that regardless of the revenue model, there is a high level of vertical integration in LNG projects through long-term contractual agreements, if not ownership. This vertical integration distributes project risks, reducing the risk for any particular component (i.e., producer, pipeline, liquefier, shipper, and regasifier), and thereby improves financing terms.

Estimates of Cost of Capital

Recognizing that borrowing rates for LNG projects are established based on economics and risk as indicated by a credit analysis, a specific cost-of-capital cannot be confidently determined in early planning stages. However, if it is assumed that the project will have low risk (i.e., known technology with creditworthy sponsors, buyers, and builders, underpinned by long-term take-or-pay contracts, etc.), and is able to meet the minimum required DSCR, we can determine reasonably likely borrowing rates and cost of capital.

Borrowing rates are determined using a base "risk-free rate," usually the LIBOR or the yield on long-term U.S. Treasury bonds, plus a spread that takes into account the riskiness of the project. As of April 13, 2011, the yield on a 20-year U.S. treasury notes was approximately 4.33%.[68] This rate is relatively low by historical standards and it would be reasonable to assume that long-term rates will increase in the future. A reasonable assumption of the future long-term risk-free rate is 5%. An estimate how much this rate would increase to account for project risk can be determined by looking at the investment grade corporate bond trading market.

As of February 2011, investment grade corporate bonds (rated BBB or higher) were trading in the neighborhood of 100 basis points above the risk-free rate. Below-investment-grade bond spreads were trading in the range of 450-750 basis points above the risk-free rate. Assuming a 5% long-term risk-free rate, this equates to a 6% borrowing rate on investment-grade bonds and a 9.5-12.5% borrowing rate on below-investment-grade bonds. Assuming that other project risks are low, a merchant project with a minimum DSCR of 2.0x or higher and tolling project with a minimum DSCR of 1.4x or higher may be able to obtain long-term funds at 6%. However, projects that have lower than the minimum DSCR are likely to borrow at significantly higher costs (9.5-12.5%) or will need to establish a Debt Service Reserve Account (DSRA) to cover debt servicing in each period with a potential shortfall in cash flow.

[68] http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

